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1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

5 PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING

6 + + + + +

7 WEDNESDAY,

8 APRIL 9, 2003

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10 ROCKVILLE, MARYLAND

11 + + + + +

12 The Committee met at 8:30 a.m. in Room T2B3, Two
13 White Flint North, Rockville, Maryland, Mario V.
14 Bonaca, Chairman, presiding.

15 ACRS MEMBERS PRESENT:

16 MARIO V. BONACA Chairman

17 F. PETER FORD Member

18 GRAHAM M. LEITCH Member

19 STEPHEN L. ROSEN Member-at-Large

20 GRAHAM B. WALLIS Member

21

22

23

24

25

1 NRC STAFF PRESENT:

2 SHER BAHADUR	Designated Federal Official
3 JOHN T. LARKINS	Executive Director, ACRS/ACNW
4 SAM DURAISWAMY	Technical Assistant, ACRS/ACNW
5 HOWARD J. LARSON	Special Assistant, ACRS/ACNW
6 TIMOTHY KOBETZ	Senior Staff Engineer, ACRS
7 P.T. KUO	NRR/DRIP/RLEP
8 NOEL DUDLEY	
9 STUART BAILEY	
10 JAMES MEDOFF	
11 DUC NGUYEN	NRR/DE/EEIB
12 JOHN FAIR	NRR/DE/EMEB
13 SIMON SHENG	
14 GREG GALLETTI	NRR/IEHB
15 CAUDLE JULIAN	NRC Region 2
16 DAVID JENG	NRR/DE/EMEB
17 JACK CUSHING	
18 J. RAJAN	NRR/DE/EMEB
19 RONNIE FRANOVITCH	

20

21 ALSO PRESENT:

22 STEVE HALE	Florida Power and Light
23 BRUCE BEISLER	Florida Power and Light
24 ANTONIO MENOCAL	Florida Power and Light

25

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1 P-R-O-C-E-E-D-I-N-G-S

2 8:31 p.m.

3 CHAIRMAN BONACA: Good morning. This is
4 a meeting of the CRS Subcommittee on Plant License
5 Renewal. I'm Mario Bonaca, Chairman of the
6 subcommittee. The CRS members in attendance are
7 Graham Leitch, Peter Ford, Graham Wallis, and Stephen
8 Rosen.

9 The purpose of this meeting is to review
10 the report with open items related to the application
11 for renewal of the operating licenses for St. Lucie
12 Units 1 and 2. The subcommittee will gather
13 information, analyze relevant issues and facts, and
14 formulate a proposal, positions and actions as
15 appropriate, for deliberation by the full committee.

16 Tim Kobetz is the CRS staff engineer for
17 this meeting. The rules for participation in today's
18 meeting have been announced as part of the notice of
19 this meeting previously noted in the Federal Register
20 on March 19th, 2003. A transcript of this meeting is
21 being kept and will be made available, as stated in
22 the Federal Register notice. It is requested that
23 speakers first identify themselves, use one of the
24 microphones, and speak with sufficient clarity and
25 volume, so that they can be readily heard.

I would like to point out that copies of these presentations are in the back of the room. In addition, a copy of the St. Lucie license renewal application is also available for reference in the back of the room. We have received no request for time to make oral statements or written comments from members of the public regarding today's meeting.

We will now proceed with the meeting. I'll call upon Mr. P.T. Kuo, Program Director of the NRC Division on License Renewal and Environmental Impacts for opening remarks.

MR. KUO: Thank you, Dr. Bonaca. Good morning, everyone. Like you said, my name is P.T. Kuo. I'm the Program Director for the License Renewal and Environmental Impacts Program. On my right is Dr. Sam Sun Li, who is the Second Chief for License Renewal Section. The staff is ready to brief the committee on the safety variation of the St. Lucie license renewal application today.

The project manager for this review is Mr. Noel Dudley. I'm sure he is a trusted familiar face to you all. He is going to lead the staff presentation with the support from the key reviewers, either with him on the table or sitting in the audience ready to answer any questions you might have.

1 There were 11 open issues at the time that
2 we issued the draft to SER. You have a copy on hand.
3 Since then, all these issues have been resolved. Mr.
4 Dudley is going to brief the committee on some of the
5 issues. I also want to point out Mr. Caudle Julian,
6 the team leader from Region II, is the team leader for
7 the St. Lucie inspection, and he will be making, also,
8 the presentation to the committee after lunch the
9 findings of his inspection.
10 We are also going to brief the committee
11 today on the staff's interim guidance development
12 process. As we promised last time, Mr. Jack Cushing
13 is going to make that presentation.
14 In the last meeting, I believe, the
15 committee indicated that you are interested in hearing
16 from us, the staff, about the operating event
17 experience process, and we have contacted responsible
18 members in the staff. They will be prepared to come
19 to the committee in the May committee meeting. So
20 there will be a presentation in May on the operating
21 event experience process from the staff.
22 So with that, if you don't have any
23 questions, and, with your permission, I would like to
24 turn the presentation over to Florida Power and Light
25 for an overview of their application and then followed

1 by the staff presentation.

2 CHAIRMAN BONACA: I have a question, which

3 I would like to get out of the way. As I opened the

4 application, page 21-6, the first thing that caught my

5 eyes was seismic II over I is not in scope; that's

6 what the application says. So I said here is another

7 issue that was supposed to be closed generically, and

8 now it's still open. Same thing I found about SBO

9 and, also, housings for dampers and fans.

10 So, in working with this stuff, I asked

11 for some clarification. I was led to page 108 of the

12 SER, where there is documentation of an interaction.

13 Requested for additional information, and I'm

14 satisfied that the components were put in scope,

15 particularly segments of piping that could possibly

16 interact with the components.

17 So, now, then I went back to the FSAR

18 supplement. I couldn't find it there. Then I went

19 back to the SER, and I looked at the Tables of

20 Commitments that you now add, which I think is a very

21 good initiative, but there is no mention of that

22 there.

23 MR. KUO: I believe Noel can address those

24 comments later on.

25 CHAIRMAN BONACA: Well, all I'm trying to

1 understand is or what I was told was that other site,
2 this segments have been brought into license renewal
3 scope. Therefore, there is a document somewhere that
4 says these components are there.
5 MR. DUDLEY: Yes, I can speak to that.
6 CHAIRMAN BONACA: I would like to hear
7 that because, again, we're talking about this endless
8 number of commitments here that are interspersed into
9 these documents. It's obvious right now, and I am not
10 going to argue with that, that the license renewal
11 application documents is obsolete by the time that the
12 SER is given because there are a lot of new
13 commitments that are not really documented there.
14 Where are they documented? I mean, do you give me
15 comfort that, 10 years from now or 15 years from now,
16 when you walk into license renewal, the applicant will
17 remember that those additional commitments were made
18 or the staff will remember when they're interspersed?
19 I don't understand.
20 MR. DUDLEY: Yes, I can make an
21 explanation. Noel Dudley, License Renewal. The SER,
22 in a sense, is a high-level document that identifies
23 what information the staff used to reach its decision
24 that the application was acceptable, and that does,
25 the SER does provide you information on locations of,

1 in this case, components that were brought into scope
2 in response to an RAI. The listing of the components
3 that were brought into scope in the RAI's is on a
4 docket and is available, and I believe everyone did
5 receive portions of the RAI's that identified
6 additional components. So that's referenced in the
7 SER and is available on a docket if somebody, in the
8 future, wants to go back and look at the details of
9 what components were brought within scope and which
10 components received aging management reviews in the
11 associated aging management programs, and it's very
12 difficult to get all of that information into the SER
13 and make the SER a readable document.
14 CHAIRMAN BONACA: No, I understand that.
15 But certainly, if I had seen in the table in the back
16 of the SER, which is additional commitments, just a
17 statement, it says "added elements to comply with II
18 over I seismic" or "seismic II over I closed," it
19 would help me, as a reviewer. I mean, I view myself
20 as almost like a member of the public that can only
21 spend two days reviewing an application of this size,
22 and I need to have some help in the being pointed out
23 where issues are closed or open, and it would be
24 helpful.
25 Now, I want to recognize that that table

1 in the back of the SER is a significant help and
2 improvement, so I would just encourage you to use it,
3 even to identify the resolution of issues that it
4 would really be noticed by us right away because they
5 were measure issues of the previous application.
6 MR. DUDLEY: As it turns out, out of the
7 79 additional components or structures that were added
8 to the scope of license renewal, 70 of them are result
9 of the responses to the II over I station blackout and
10 fan and damper housings. So I can see where we could
11 very easily add that statement in the commitment
12 section to identify what major components were.
13 MEMBER LEITCH: I had a similar question
14 right on that very same point. A number of the
15 applications we've seen in the past, where they had
16 non-safety systems in a II over I situation, they
17 looked at every place where a non-safety system ran
18 through a seismic Class I building and considered that
19 entire portion of the safety system to be within the
20 scope.
21 Now, from reading this, it seems as though
22 that's not exactly what St. Lucie has done, but,
23 rather, they've done it on a more spatial basis and
24 just certain portions of non-safety systems that are
25 running through seismic Class I buildings that are

1 included in scope. And I guess my question just,
2 perhaps, further on Mario's point is do we have
3 documentation, you know, clear documentation on the
4 docket as to exactly what portions of non-safety
5 systems are in scope and which ones are not. In other
6 applications, they just kind of said any part of this
7 system that runs in a seismic Class I building is in
8 scope, but I don't think that was done here.
9 MR. HALE: Yes, let me speak to this, if
10 I could.
11 MR. DUDLEY: I'll just give a broad
12 overview. That will be discussed in more detail when
13 we talk about the scoping screen methodologies, and
14 that was looked at in detail during the scoping and
15 screening audit that Greg Galletti will talk about
16 later in the presentation. I can turn that over to
17 Steve.
18 MR. HALE: In the area of scoping and
19 screening, you know, the application is only a
20 presentation of all the detailed technical information
21 that we maintain on-site. One of the things we chose
22 to do early on was reflect license renewal boundaries
23 on our PNID's, permanent plant drawings. So, you
24 know, every so often, PNID's are submitted to the NRC
25 as part of the update process, and on those PNID's,

1 you'll see license renewal boundaries, even for these
2 II over I.
3 Now, in the scoping area, we chose that,
4 as these volumes, we've got a bookcase full of
5 technical documents which support what we have.
6 They're Q8 engineering-type evaluations, which support
7 the information we submit. And in the scoping area,
8 we actually revised our technical documents to reflect
9 those changes and identified any permanent plant
10 documents that would have to be revised as a result of
11 that. So it's really at a level below the SAR, but it
12 is incorporated into our documentation, so we have all
13 that stuff documented.
14 And, as part of the scoping and screening
15 inspection, the folks came in and actually looked and
16 walked down those portions of the piping to verify
17 that we had, indeed, captured the appropriate piping
18 in the scope of license renewal and that it was
19 adequately reflected on the drawings.
20 To speak to the fact that we hadn't
21 addressed the II over I, the station blackout and the
22 -- what was the other -- damper housings, we were
23 already into the technical documentation aspect or the
24 technical document preparation for St. Lucie and it
25 was just one of timing. We actually started doing our

1 evaluation on II over I, station blackout, and the
2 housings based on what was done at Turkey Point, so
3 that we were able to address it at the RAI stage,
4 rather than the open-items stage for St. Lucie. And
5 anything that we do forward from here, we would have
6 gone ahead and put in consistent with the staff
7 guidance. So it was really a question of timing for
8 us for St. Lucie.
9 MEMBER ROSEN: I have a question on P.T.'s
10 opening remarks. I was listening for whether or not
11 you're going to talk to us about the ROP status of St.
12 Lucie any time today?
13 MR. DUDLEY: Yes, that's built into the
14 presentation.
15 MEMBER ROSEN: When is that?
16 MR. DUDLEY: I think that's before
17 lunch. MEMBER ROSEN: Item four? Okay.
18 Thank you.
19 MR. DUDLEY: Any more questions?
20 MR. HALE: My name is Steve Hale. I'm the
21 License Renewal Manager for Florida Power and Light.
22 I was responsible for Turkey Point and St. Lucie
23 license renewal. It's good to see a lot of the
24 members that actually visited Turkey Point.
25 With me today is Bruce Beisler, who is our

1 civil lead. There were some questions that were
2 presented to us early that there wanted to be
3 discussion relevant to concrete subject to ground
4 water, so Bruce is here to discuss that.
5 Also with me is Tony Menocal, who is our
6 technical lead. He was responsible for development of
7 all the technical documents which support our
8 application.
9 What I'm going to talk about today is
10 background. I will talk about the scoping and
11 screening process, but since it was, essentially, the
12 same one that we used for Turkey Point, I would like
13 to focus more on the aging management review, aging
14 management program, and TLAA areas, if I could. I
15 will go through the scoping and screening process, but
16 I would like to emphasize it's just like the one we
17 used for Turkey Point.
18 One of the things I'll get into in the
19 aging management review programs is the GALL report
20 was issued while we were preparing the St. Lucie
21 technical documents and application, and we had a
22 request for Chris Grimes to at least try to address
23 the deltas between our report and what was in the GALL
24 report. Although we don't follow the new SRP format,
25 we're consistent with the hot level on the SRP, but

1 some of the details we did address GALL in the
2 application, and we did credit GALL for some of our
3 programs.
4 With regard to license renewal FPL, I've
5 been involved with license renewal since about 1992.
6 I was on the NEI task force, and I was also on the
7 Westinghouse Owner's Group license renewal group. The
8 Turkey Point license renewal application was submitted
9 in September of 2000. We initiated the technical
10 work. We essentially took the same technical team
11 that had done the evaluations for Turkey Point and
12 moved them to St. Lucie when they actually started
13 doing that work up at St. Lucie.
14 We submitted the St. Lucie license renewal
15 application in November 2001. And just a note here,
16 we did receive our renewed licenses for Turkey Point
17 on June the 6th, 2002.
18 The guidance requirements, these are
19 fairly standardized now with regards to license
20 renewal. 10 CFR Part 54, the SRP has been issued now,
21 which it hadn't before with Turkey Point, the GALL
22 report, the Reg Guide, NRC position letters on generic
23 issues, as well as now the new staff guidance letters
24 and 95-10.
25 With regards to the technical work that's

1 performed on-site, we piloted our procedures in 1996
2 in support of the Turkey Point effort. We structured
3 our procedures out of making the best use of the tools
4 we had available, our electronic databases, our
5 PNID's, our SAR, and our DBD's. We made information
6 trips to other applicants that were active in the
7 license renewal area, and we spent a lot of time with
8 the Duke folks because, early on, Oconee seemed to be
9 more in line with the type of thing that we wanted to
10 do, although we felt we improved on their techniques.
11 What we try to incorporate, and this
12 really goes to the issue of station blackout, II over
13 I the results of the NRC review of Turkey Point
14 license renewal application, also lessons learned,
15 RAI's and RAI responses, and resolution to generic
16 issues were factored into our procedures, where they
17 were available and where we could.
18 Because we were in the process of
19 negotiating and trying to resolve the station blackout
20 issue and the II over I issue for Turkey Point, we
21 really didn't know what the end point was going to be.
22 And before we actually went down that path, we wanted
23 to make sure we had a good idea as to what was going
24 to be done in terms of resolution for Turkey Point
25 before we did that for St. Lucie because there's quite

1 a bit of engineering work involved.

2 One thing we did want to flag is that we

3 did do all of our technical work under our quality

4 assurance program. The technical documents were

5 subject to auditing by our QA group. Turkey Point,

6 they participated at various stages, and, at St.

7 Lucie, they tended to focus on differences between St.

8 Lucie one and two was one of the areas they took a

9 look at. But it was done under the QA program.

10 MEMBER FORD: Steve, I know you just

11 talked about TLAA's in the previous diagram, you were

12 talking about lessons learned, etcetera, etcetera.

13 You'd assume, therefore, the number of open issues

14 would be decreasing with time. I don't know if that's

15 the case here. Are we, in fact, learning from the

16 past? Could you make a comment on the number of open

17 issues? I know they've all been resolved at this

18 time.

19 MR. DUDLEY: Yes. Noel Dudley, license

20 renewal. For Turkey Point, there were about, I've got

21 it later in the presentation --

22 MEMBER FORD: Okay, fine.

23 MR. DUDLEY: But there was about a 70

24 fewer RAI's for St. Lucie as there was at Turkey

25 Point.

1 MEMBER FORD: Okay.

2 MR. DUDLEY: The assessment of why that is

3 is a longer discussion.

4 MR. HALE: Yes. I think my perception is

5 that, you know, you reach a deadline to issue the SE,

6 and these items were just, we essentially, between us

7 and the NRC, ran out of time to resolve them through

8 the RAI process, so you just kind of draw a line in

9 the sand, the issue of the SE with the open items,

10 and, in the process, we've been able to resolve them.

11 So I don't think there were really hard spots. There

12 were more clarifications and more information was

13 required from us.

14 But from the RAI process, I felt we had a

15 very positive interaction. We learned quite a bit

16 from Turkey Point. We followed the same process where

17 we would sit down with a staff in open public meetings

18 to review draft RAI's, and if we could point to

19 correspondence where that information could be

20 addressed, then we were able to avoid having an RAI

21 issue. And on the same tact, we issued draft RAI

22 responses and then had open public meetings with the

23 staff, where we would go over those and make sure that

24 our responses were addressing, indeed, the concern of

25 the reviewer. We've always taken the tact that it's

1 better to have that face, one-on-one interaction with
2 reviewers to really understand what the issues are.
3 So as a result of that, we had about 150
4 so RAI's for St. Lucie, and we had over 200 at Turkey
5 Point. I think there was quite a bit of lessons
6 learned there. And I look at it also from the
7 standpoint, you know, look at licensing fees. The
8 review of St. Lucie is significantly lower in terms of
9 licensing fees versus Turkey Point, and I think that's
10 an indicator that our review is getting more efficient
11 and better because they're essentially the same
12 format, the same type of documents.
13 As far as the application format, it's the
14 same as Turkey Point. We included admin information
15 in Chapter One, the scoping and screening is covered
16 in Chapter Two. Chapter Three covers the AMR's. And
17 Chapter Four is the time limit of aging analysis.
18 It's very similar to A&O, Turkey Point, the Duke
19 units, McGuire and Catawba, and Surry and North Anna.
20 NXA is UFSAR supplement. In the case of
21 St. Lucie, that's two supplements because Unit 1 and
22 Unit 2 each have their own SAR. Aging management
23 programs are prescribed in Appendix B. Appendix C is
24 just a summary of the process we utilized for
25 establishing aging effects for non-Class I components.

1 Appendix D is spec changes; we had none. And then the
2 environmental report was the separate document
3 attached to the application.
4 Our source documents, we used the UFSAR;
5 our licensing correspondence, we have an electronic
6 database with all of our correspondence from the
7 beginning; our design basis documents for Unit 1 and
8 Unit 2, our electronic component database, which has
9 controlled engineering fields in terms of safety
10 classification, you know, tag number, this sort of
11 thing. Our drawings, primarily, are PNID's and our
12 control wiring diagrams. And in some cases, we
13 actually got into other documents at the plant, but
14 these are the primary information sources we have for
15 scoping and screening.
16 Our methodology is described in section 2-
17 1. Again, it's the same as we utilized for Turkey
18 Point, and it follows the approach that is in 95-10.
19 In the scoping area, what is the purpose? It's really
20 to identify, on a system and structure basis, which
21 ones are within the scope of license renewal. Again,
22 to reiterate the Part 54 criteria, it's those SSC's
23 that are safety related, non-safety related which can
24 affect safety related, and those that are related to
25 five regulated events, which include fire protection,

1 EQ, PTS, anticipated atlas, and station blackout.

2 With regards to safety related, the
3 safety-related definitions in Part 54 is the same as
4 in our current procedures and quality instructions.
5 We used the SAR, tech specs, our licensing
6 correspondence, DBD's, our component database, and
7 design drawings to establish which systems and
8 structures were safety related. And I think this is
9 an important point, we even looked at all non-safety
10 related systems and structures to confirm there were
11 no components in those systems that were classified
12 safety related as part of a validation that we had
13 captured.

14 With regards to non-safety which can
15 affect safety, which is probably the most difficult
16 portion of the scoping effort, we used SAR, tech
17 specs, and licensing correspondence, DBD's, our
18 component database, design drawings, and pipe stress
19 analyses. This was really to establish how much of the
20 pipe is in the seismic analysis because, up front, we
21 did include that piece of pipe.

22 We see two categories. One that actually
23 provides functional support. In other words, it needs
24 to run in order for the safety system to work. And
25 the other is one where the non-safety system could

1 actually, through failures, could actually affect the
2 safety-related component.
3 In the regulated events, we used, again,
4 the SAR, tech specs, licensing correspondence, DBD's,
5 component --
6 MEMBER LEITCH: Steve, just back on that
7 previous one where you were talking about potential
8 interactions. Was that done by physically walking
9 down and looking at the configuration of some of this
10 equipment?
11 MR. HALE: It does. The approach we took
12 to II over I was an area-based approach, and, right up
13 front, we included all the non-safety related
14 supports. If we had an area where there was non-
15 safety and safety-related equipment, we basically
16 included all the supports, all the conduit that was
17 non-safety related. The only thing we didn't include
18 was the pipe because, from a design-basis standpoint,
19 our pipe was never classified that way. So we were
20 trying to do it consistent.
21 Now, there were portions of pipe as part
22 of the Unit 2 licensing basis that was specifically
23 designated as seismic in our licensing basis, but the
24 basis for both Unit 1 and Unit 2 was not so much non-
25 safety which can affect safety, it was from a seismic

1 event as an event whether you could shut down the
2 plant. So you may have certain components that don't
3 come into play in shutting down the plant, whereas
4 they would be in play, like the hot-pressure safety
5 injection pumps during an accident. So the design
6 bases were different. We tried to clarify that in our
7 II over I response.
8 But we understand what the staff's concern
9 is, and we evaluated it based on the Interim Staff
10 Guidance that was issued and what we had done for
11 Turkey Point.
12 MEMBER LEITCH: Again, I'm still a little
13 confused. Was most of this work done by reviewing
14 documents, or was --
15 MR. HALE: No, we actually did field walk-
16 downs. We went out and walked down the plant. We
17 identified every non-safety related system in safety
18 related areas. We physically walked down and looked
19 at it. And again, like I said, one of the inspectors
20 who came in for the scoping and screening inspections
21 actually went and, you know, looked at what we had
22 done and actually went into some of these areas to
23 actually see what we've inspected.
24 MEMBER LEITCH: Okay, thanks.
25 MR. HALE: Yes. There was quite a bit of

1 field work involved with it. I guess from the II over
2 I standpoint, there was other things we had to look
3 at. We had to look at flooding. We had to look at,
4 you know, a wide range of other type of events outside
5 of the seismic interaction.
6 MEMBER ROSEN: Steve, you mentioned that
7 you marked the drawings to show components that were
8 now in license renewal scope; am I correct?
9 MR. HALE: Right.
10 MEMBER ROSEN: Which drawings did you mark
11 when you're talking about these non-safety related
12 systems which can affect safety related? Just marking
13 PNID's would seem not adequate to me.
14 MR. HALE: We actually had to draw a wall,
15 so we actually put some spatial lines on the drawings
16 that says "in the P-pump room" or, you know, that sort
17 of thing.
18 MEMBER ROSEN: So you had to augment the
19 existing PNID's?
20 MR. HALE: Exactly, exactly.
21 MEMBER ROSEN: If you're using just PNID's
22 to do that because they don't really represent the
23 lengths of pipe.
24 MR. HALE: Right.
25 MEMBER ROSEN: I mean, they're

1 abstractions for the reality that's out in the plant.
2 MR. HALE: Yes, that's true. And that's
3 a good point because we ran into that issue when we
4 actually started to go down and physically designate.
5 In some cases, it was between valves, but, in other
6 cases, we actually had to draw, you know, like, for
7 example, at St. Lucie, we have a room which has got
8 some swinging switch gear on the 19-5 level, and we
9 actually drew a wall that says "non-safety related
10 pipe in AB switch gear room," so that's actually
11 marked on the drawings now.
12 MEMBER ROSEN: Okay. You've answered the
13 question with respect to the PNID's. Did you go down
14 to the next level of drawings, say the isometrics, and
15 annotate them for what's in storage?
16 MR. HALE: No, because when you really
17 look at it, what it is that, when we look at our
18 inspection, what really is the end point? The end
19 point is, on some of this piping, you're going to do
20 external visual inspections, okay, and you're going to
21 monitor the piece of pipe that you're talking about.
22 And the PNID's were adequate for that aging management
23 program that you're doing. You really didn't need to
24 go into the isometrics to do that.
25 If we felt we had to to appropriately

1 identify it to the people that are actually going to
2 be doing the aging walk-downs and that sort of thing,
3 then we would have. But we didn't find it necessary
4 in what we were dealing with. Most of it was just
5 straight runs of pipe in a room, you know, where we
6 could draw boundaries at the walls.
7 Anymore questions on that area? I mean,
8 when I first got involved with license renewal, I
9 said, "You know, safety related and regulated events,
10 that stuff is pretty well documented. You can access
11 your CLB's. But when you get into this area of II
12 over I, it's probably the most complicated." And it's
13 an area that we need more details and guidance on how
14 to approach it, and I think the ISG has really helped
15 us, you know, focus on what it is we need to look at
16 and how we need to approach it.
17 Okay. On the regulated events, there were
18 some other documentation we utilized. We have a
19 control document called the Appendix R Safe Shut-Down
20 List. We also have an item called the Essential
21 Equipment List; EQ List, which is derived right out of
22 our component database, and we also have a Load List
23 that we use to confirm that, in the St. Lucie Unit 1
24 case, where we credit the Unit 2 diesels that there's
25 adequate power or that the diesel can accommodate a

1 blackout at one unit, as well as a loss of off-site
2 power on the other unit.
3 Just a summary of the scoping of systems
4 and structures. For St. Lucie, 39 out of 70 systems
5 were in scope, and 16 out of the 46 structures on-site
6 were in scope. We did include layout figure in
7 Chapter Two or section 2.2, which shows the structures
8 that are in scope on the site.
9 In screening, the purpose is to identify
10 structures and components which require an aging
11 management review. The criteria is what we call
12 component-level scoping. Once you've identified the
13 entire structures in the scope, then you go down to
14 the structure systems in the scope, you go down to the
15 component level, and then you do your screening or you
16 look at whether it's passive or not and whether it's
17 long-lived or not.
18 In the mechanical area, we established
19 evaluation boundaries and interfaces with other
20 systems so that we made sure we captured everything.
21 We identified the specific structures and components
22 that were included in the systems evaluation
23 boundaries. We looked at the intended functions, and
24 then we identified which ones supported those
25 functions from a passive standpoint. We also

1 evaluated them, whether they were long-lived. And in
2 this area, we actually got into plant procedures and
3 that sort of thing. There had to be specific
4 references if things were replaced based on a specific
5 life that would be documented in our technical
6 documents.
7 MEMBER LEITCH: Can I ask a little bit
8 about that passive classification? I guess I'm
9 beginning to develop a little concern about electronic
10 components, power supplies, and things of that nature.
11 And some of this may be, you know, beyond the scope of
12 the rule, but I'm just wondering, I think, by nature,
13 you've classified electronic components as active,
14 generally, and, therefore, they fall out of the
15 screening process.
16 What I'm beginning to notice as I review
17 operating experience that there seems to be a growing
18 trend of plant upset condition, Scrams, so forth --
19 I'm not necessarily talking St. Lucie, I'm talking
20 about the industry in general -- that are the result
21 of failed electronic components. And I'm just
22 beginning to come to the conclusion that, perhaps,
23 generally, as plants approach the age that they're
24 approaching now, that we're going to have some
25 failures in electronic components.

1 Now, some of these are active in a sense
2 that the failure can be detected by maintenance
3 procedures, surveillance tests. You do a surveillance
4 test, and you find a component that's failed. Some of
5 them are revealed by a half-scram or one channel of
6 logic, but some of them are revealed in a kind of
7 unfortunate way. They scram the plant, or they close
8 some other kind of upset conditions.
9 I guess I'm just wondering do you have,
10 independent of license renewal, is there some kind of
11 a program to assess which electronic components whose
12 failure could, all by itself, cause an undesirable
13 chain of events.
14 MR. HALE: Yes, and I think, you know,
15 that that's a perception that I have to put on when I
16 think is that, just because it doesn't get included as
17 an aging management review for license renewal doesn't
18 mean we're ignoring it or we're not addressing it.
19 One of the bases in the revisions of the rule, which
20 was in the 95 - 96 timeframe, was that we do have a
21 lot of programs that look at active components, plus
22 surveillance, tech specs, and the fact that that stuff
23 does get bubbled up in operating experiences is one
24 indicator that this stuff is being looked at and
25 watched and actions are being taken.

1 I can't speak for other utilities, but we
2 have breaker programs, you know, where we have a set
3 preventative maintenance where we go into all of our
4 breakers, which are an active component, but, you
5 know, they get a lot of attention. Certainly, all of
6 our instrumentation that is covered by tech specs gets
7 tested regularly. You have surveillance testing, this
8 sort of thing. Then, as certain issues arise, like
9 Agastat relays that are energized, you know, all the
10 time, we had to start replacing those like every three
11 years. You know, those sort of things. But a lot of
12 the reason why we don't address the active stuff and
13 license renewal is because it's an overlap of
14 everything we're already doing in that area. So, you
15 know, I've tried to communicate that, as well, to the
16 people I talk to just because it's not in license
17 renewal aging management review doesn't mean that
18 there aren't programs out there that are addressing it
19 and, in specific, looking ahead.
20 We also have some strategic plans looking
21 at obsolescence of instrumentations and controls at
22 St. Lucie and Turkey Point, you know, in terms of
23 long-term, looking at what's called lifecycle
24 management, looking at instruments that you no longer
25 have spare parts for. There's quite a bit of activity

1 right now in our utility looking at those active
2 electronic components. So I give you assurance that
3 we're paying attention to it.
4 And if you look at maintenance rule, for
5 example, it carries trips, you know, PRA; there's a
6 number of other components that are included in the
7 maintenance rule monitoring specifically related to
8 some of those active components and systems.
9 MR. KUO: And Dr. Leitch, if I may
10 interject really just a brief background to offer the
11 true rules. In 1991, we had one rule, and we had also
12 demonstration project that we using as the example. At
13 that time, we did include the active and passive
14 components, and that was one of the lessons we learned
15 from '91 is that, gee, after we reviewed all this, it
16 appears that all the components, they have programs to
17 deal with if they're ready. There's really no need
18 for us to have any additional aging management program
19 for that, and this was based on the conclusion also
20 from the prior program, the new aging research
21 program. We had about 150 research reports on that.
22 So as part of the lessons learned, we
23 advised the rule in 1995. It was published in
24 December of 1995, and also, at that time, we had
25 established the maintenance rule, which is the basic

1 focus mostly on the active components. Later on, the
2 passive components were included.
3 But because of all these background
4 information, that was how we revised the 1995 rule. We
5 do have a sufficient activities there to make sure
6 that active components are being taken care of, and
7 what we really are not too sure about are those
8 passive components.
9 MEMBER LEITCH: Okay, thank you.
10 CHAIRMAN BONACA: Well, on the same
11 length, since we are interrupting with questions, I
12 would like to ask another question on this. I was
13 reviewing the pressurizer spray, and there you have a
14 screening process by which you conclude that the
15 pressurizer spray head should not be in scope. And
16 the reason was that the function of the spray head is
17 the one of, essentially, enhancing the efficiency of
18 the spray. And you went through an elaborate
19 demonstration of why you're going to need to do that.
20 You can survive an event where you need to spray the
21 pressurizer for protection purposes, but you can do
22 without the enhanced effect of the spray head.
23 When I look at the kind of discussion that takes a
24 number of pages here and there, I'm left with an
25 impression that we were on this plant maybe with

1 components, like a spray head, that would fail before
2 anything is done to it. And I'm sure that's not the
3 way you want to run the plant. So I'm trying to
4 understand the logic. I mean, these discussions are
5 not only about the pressurizer spray head; there are
6 other examples of that. Do you have any inspection of
7 the spray head ever done, or is it part of -- I was
8 left to the question, you know, are they ever going to
9 look at the spray head, given that you have a
10 component which is subjected to significant thermal
11 cycle and, therefore, I'm not sure it's going to break
12 without cracking for 60 years.
13 MR. HALE: Well, to give you some history
14 on this, we took the position that the Westinghouse
15 Owner Group originally took in their topical. We used
16 that position at Turkey Point. The aging effect is
17 thermal embrittlement of stainless, it's not the
18 fatigue issue. And there's some question as to what
19 that real effect would be, you know, whether you'd
20 really see that effect in the spray head. You know,
21 there's not a lot of data on extended, you know,
22 usage, that sort of thing.
23 Our feeling, from an aging management
24 standpoint, is not that this thing was going to fail.
25 One, we had a technical argument why it should be in

1 scope from a functional standpoint. I mean, I look at
2 our challenges, as an engineering organization, and
3 the rule is very prescriptive in terms of what's
4 required to be in scope, what isn't. So we go through
5 that process, and our conclusions were it in weren't
6 in scope. I think my own opinion is that we probably
7 are not going to see anything with the spray head. If
8 we ever do go into pressurizer for any reason, we'd
9 probably look at the spray head; we would probably
10 recommend that. But do we have to? Our feeling is we
11 don't. And, you know, there's a lot of those to say
12 that we have to do that means we've got to open the
13 pressurizer, we've got to, you know, subject folks to
14 dose and that sort of thing.
15 But we also got to look at the failure.
16 If it does crack, what does that mean? Okay. It's
17 not going to affect your safety functions, okay, but
18 you may lose some efficiency and control. Is that
19 something we want to happen? Certainly not.
20 I don't know if I answered your question,
21 but the main reason is we have taken that position at
22 Turkey Point. We utilized the same position at St.
23 Lucie. There were some additional questions that were
24 raised. We tried to demonstrate why we came to the
25 conclusion we did.

1 CHAIRMAN BONACA: Thank you.

2 MR. HALE: In the civil area, I went for

3 the next slide there.

4 MEMBER WALLIS: What does long-lived mean?

5 MR. HALE: Long-lived means it's not

6 replaced on a regular sequence or schedule. In other

7 words, we assume stuff was long-lived if we didn't

8 have specific --

9 MEMBER WALLIS: So no life is specified?

10 MR. HALE: Right, right. What we required

11 of our engineers when they were doing their

12 evaluation, there had to be specific maintenance

13 procedures that require replacement of these

14 components regularly before we would take that

15 position. So, you know, we just couldn't say, "Well,

16 we think we replaced that periodically." There had to

17 be specific references that were quoted. A good

18 example is filters on HVAC equipment, like in your

19 house or things you might have on motors. You know,

20 we have a set frequency. We replaced those every 30

21 days or whatever the frequency might be. There could

22 be a specific maintenance procedure that calls for

23 doing it.

24 MEMBER WALLIS: It's not the 30 days, but

25 it's when you get up to 10 years or something, then

1 it's sort of a fuzzy area.

2 MR. HALE: Around 40 years is the

3 criteria. If it's not replaced on a frequency that's

4 less than 40 years, then it has to be included as a

5 long-lived item.

6 In the civil area, it's pretty much the

7 same approach. But in this case, you've got the

8 electrical all inside, when you get into the civil

9 structural area, almost everything is in scope because

10 it's all passive, you know? So maybe that offsets the

11 electrical piece.

12 CHAIRMAN BONACA: I'm sorry. Just to

13 close the issue of pressurizer, you're going to

14 inspect, however, the thermal sleeves of the

15 pressurizer header, right?

16 MR. HALE: No.

17 CHAIRMAN BONACA: Or the spray header. No?

18 MR. HALE: No, no. If you will look in

19 that, the pressurizer sleeves are not welded. The

20 issue there was whether the sleeve would, correct me

21 if I'm wrong, Tony --

22 CHAIRMAN BONACA: That was the weld.

23 MR. HALE: Yes, welded. It's actually

24 expanded, pressed into the nozzle itself.

25 CHAIRMAN BONACA: I see. And so --

1 MR. HALE: So it's no connection to the
2 pressure boundary.
3 CHAIRMAN BONACA: Okay. So you would not
4 look at it?
5 MR. MENOCAL: There would be no need to.
6 MR. HALE: We do look at, certainly, the
7 welds associated with the nozzle itself.
8 CHAIRMAN BONACA: Okay.
9 MR. HALE: In the electrical and I&C area,
10 as you mentioned, we do take a slightly different
11 approach. This is more for efficiency of our review.
12 We actually eliminate the active components up front
13 because, again, you know, 95% of the electrical
14 components are active. The example I give is the
15 first time I did a component download on our 40-volt
16 system at Turkey Point, I got 18,000 components. And
17 to go through and say "active, active, active,
18 active," it made more sense to eliminate the active
19 categories up front and then deal with the passive
20 components.
21 And again, the one point we want to make
22 in the electrical area, if something was in the EQ
23 program, it is replaced on a qualified life. So even
24 though some of these components may be greater than 40
25 years, the fact that it is in the EQ program allowed

1 us to eliminate it as a long-lived item. This is
2 consistent with what previous utilities have done.
3 As far as the screening results, the
4 results are summarized in Chapter Two and then the
5 details are presented in Chapter Three's six-column
6 tables where we list all the specific components
7 relative to each system structure. There are four
8 mechanical sections: rack and cooling system,
9 connective systems, ESF, auxiliary systems, and steam
10 and power conversion. Next is the structural area and
11 then the electrical area. We did cement license
12 renewal boundary drawings to facilitate the NRC review
13 of our application, and we also included a SAR on the
14 CD that we submitted, which allows the reviewer to
15 actually link to the specific SAR sections or link to
16 the specific drawings on the CD that we had submitted.
17 Now I'd like to shift into the aging
18 management review. This is a definition that's in the
19 regulations, essentially, that we demonstrate that the
20 effects of aging will be adequately managed, so the
21 intended functions will be maintained consistent with
22 the CLB for the extended period of operation.
23 How do we go about this? What I'd like to
24 just communicate to you is that we had two areas.
25 Aging effects requiring management were established

1 based on two primary areas: the AMR technical
2 resources we had available to us and our operating
3 experience reviews. The methodology we used for
4 determining the aging effects requiring management for
5 non-Class I in the civil and structural area is in
6 Appendix C. This is an approach that was originally
7 developed by the B&W owner's group. It was then
8 adopted by the other SSS owner's group and has now
9 been placed with EPRI, and so it's now a standardized
10 tool for the industry to utilize.
11 As far as in the technical resources area,
12 even though this is not a Westinghouse plant, there's
13 a lot of good information that was developed in the
14 Westinghouse generic technical report. I believe
15 about five of those were submitted for NRC review.
16 There's another 10 that were developed for us by
17 utilities, we utilized those; The original NUMARC
18 license renewal industry reports, I believe, late
19 80's, early 90's. Again, we mentioned B&W tools. We
20 had a big database from the Turkey Point aging
21 management reviews. We had a new document we
22 utilized, which was the GALL report, and, in some
23 cases, because we did have some unique materials at
24 St. Lucie, we had to get into materials handbooks and
25 in-house materials expertise. We do have

1 metallurgical folks on staff, and we do have a
2 metallurgical lab.
3 MEMBER WALLIS: Steve, I'm sure it was a
4 slip of your tongue, but when you sort of talk about
5 the GALL report, you said you could have used. You
6 did use?
7 MR. HALE: We did use it. I'm sorry, yes.
8 It was issued during the St. Lucie development of our
9 technical documents. Yes, we did use it.
10 And then, again, our participation in
11 industry groups. I don't know if you were aware, but
12 there are, like, three technical groups in addition to
13 NEI, which is groupings of mechanical, civil, and
14 electrical license renewal utility engineers, which
15 meet periodically to discuss issues and how to address
16 certain aspects of the reviews, as well as how you
17 address aging and certain areas. So we were active
18 participants in all three of those groups.
19 MEMBER ROSEN: Steve, I was interested in
20 your comment that you have some unique materials at
21 St. Lucie. Could you just expand on that on a bit?
22 MR. HALE: Yes. The Unit 1 RWT is
23 aluminum. The one area that we found there was no
24 industry information, I won't say materials, maybe
25 some chemicals, was we have a sodium hydroxide tank

1 that isn't unique, but we couldn't find any
2 information, so we had to go research on the aging
3 effect of sodium hydroxide on stainless. Unit 2 has
4 hydrazine. We're trying to look at data. You know,
5 we're trying to go into a mechanical handbook looking
6 for industry information on how that's done. But I
7 guess RWT is really the unique component. It's
8 aluminum. Unit 2's a stainless.
9 MEMBER FORD: Along that seems sort of the
10 line of questioning, Steve, you're absolutely correct.
11 All of those documents that you described are very
12 useful resource. However, aging phenomenon
13 fortunately change with time, as do materials.
14 What sort of license do you have or do you
15 exercise on yourself to make use of the evolving
16 knowledge that have accrued since those documents were
17 published? For instance, 600 techniques, are they
18 still valid since they were evolved in the mid 1990's
19 and so on? What sort of license do you allow yourself
20 to make use of the evolving knowledge?
21 MR. HALE: Well, on specific industry
22 programs, like MRP, we're tied into MRP, which is the
23 group that's looking at various material aspects in
24 the reactor vessel internals area. We do participate
25 on the number of industry groups. We do look at

1 operating experience on a regular basis. But in terms
2 of getting out ahead and trying to be proactive, other
3 than in the research area through EPRI, there really
4 isn't a lot that we have that we can go to or draw on,
5 I guess.
6 MEMBER FORD: Okay.
7 MR. HALE: But we do participate in
8 industry groups. I think the industry, as a whole,
9 tends to use EPRI for their R&D. We do have a number
10 of metallurgists on staff. In fact, one metallurgist
11 was involved directly. You know, when we get this B&W
12 tools thing, then you need to apply it to your own
13 site in terms of have we seen in this system or that
14 system, what have seen metallurgically in terms of SEC
15 in certain areas of the plant. We did try to gain
16 that knowledge. We did draw on the industry in terms
17 of potential aging effects, in terms of evaluating
18 them. And then we had a lot of operating experience.
19 But I would have to say, in terms of getting out ahead
20 of things, our primary means is through industry
21 groups and EPRI.
22 MEMBER FORD: Okay.
23 MR. HALE: We're pretty proud of our
24 operating experience reviews. We did a fairly
25 detailed and a long look backward in terms of what's

1 happened at our power plants. We did look at NPO and
2 NRC generic communications and looked at, you know,
3 what our responses were to all those documents.
4 That's all captured in our technical documents, review
5 of those.
6 We went back and looked at non-conformance
7 and condition reports throughout the history of the
8 plant. We looked at response team and license event
9 reports. The event response team is something that's
10 formed, like, if you have a plant trip or in some
11 significant event where you need to evaluate that.
12 We went and looked at all of our
13 metallurgical laboratory reports. When you get into
14 some unique aging effects and things of that sort, we
15 really don't know what the root cause was. They were
16 evaluated in our metallurgical lab, you know, electron
17 microscopes, things of this sort; and we factored the
18 results of that into our aging management reviews.
19 And then we had specific discussions with the system
20 and component engineers at the plant, as well as
21 specific walk-downs of the systems.
22 This review of operating experience is
23 important in two aspects, I think. One is it helps
24 you in identifying aging effects, which may come
25 about, but it also established that we are managing

1 aging in our plants. We're looking at things, we're
2 evaluating them, and we're correcting them.
3 MEMBER LEITCH: This may be a little in
4 the environmental area, but when I look at event
5 reports and I see one from St. Lucie, it seems like
6 90% of the ones I see from St. Lucie have to do with
7 sea turtles. What's the story there with sea turtles?
8 MR. HALE: Well, the sea turtles --
9 MEMBER LEITCH: It's just a curiosity
10 question.
11 MR. HALE: There are various sea turtles
12 that are endangered species, and we're required by our
13 consultations with the environmental, NMS, National
14 Marine --
15 MEMBER FORD: Fisheries Services.
16 MR. HALE: Yes, I guess. And document
17 that. In fact, we just invested close to a million
18 dollars in a new turtle net. We've got an intake
19 canal with a pipe that goes out to the ocean. We have
20 a velocity cap on that to try and, you know, keep fish
21 and that sort of thing from getting into the intake
22 canal. But once it gets into the intake canal, if you
23 have an endangered specie, you want to ensure that he
24 stays healthy. And what we have is we have a net that
25 comes up, and the turtles, you don't want them to

1 drown, basically, so we have a crew that's out there
2 continually. In fact, the environmental league of my
3 project actually went out and helped them pick up one
4 that weighed about 800 pounds about three months ago.
5 MEMBER FORD: Really?
6 MR. HALE: But every time we capture one
7 of those, you know, it needs to be reported.
8 MEMBER FORD: Then they're alive? I mean,
9 even if they're --
10 MR. HALE: Yes. And then you have to
11 establish, if they are injured, whether it was due to
12 plant operation or he has, you know, some other
13 illness or that sort of thing. And if one has been
14 killed or is dead, they actually do autopsies to
15 evaluate the cause of death. But we're limited to a
16 certain percentage of the total intake as to, you
17 know, mortalities if it's due to plant operation.
18 That's why you see that, and you see it from Crystal
19 River, too. They have a similar type of situation.
20 MEMBER LEITCH: You don't seem to notice
21 it at Turkey Point; that's a different situation?
22 MR. HALE: Yes. We don't really get that
23 kind of wildlife. In fact, it's actually reserved for
24 the endangered crocodile at Turkey Point.
25 MEMBER LEITCH: I see.

1 MEMBER ROSEN: This question is not on
2 turtles.
3 MR. HALE: Okay. Bruce knows all about
4 it. He was responsible for the design of the turtle
5 neck.
6 MEMBER ROSEN: Let's go back to the
7 aluminum thing --
8 MR. HALE: Okay.
9 MEMBER ROSEN: -- the fueling storage
10 thing in Unit 1. You switched to stainless steel for
11 Unit 2?
12 MR. HALE: Yes.
13 MEMBER ROSEN: Was that because of
14 unsatisfactory performance in Unit 1's aluminum tank?
15 MR. HALE: No, I believe it was a more
16 standard material. We have had issues with the
17 aluminum tank, but I don't think that was the reason
18 for the decision.
19 MEMBER ROSEN: What sort of metallurgical
20 issues were there in one tank, and can we have
21 confidence in it that it will last for 60 years?
22 MR. HALE: Yes, yes. And we actually have
23 a program, as part of Section 11, to go in and inspect
24 that tank regularly. We have, like an epoxy coating
25 on the bottom that has to be inspected, and we

1 identified that in the application. It requires
2 inspection.
3 MEMBER FORD: Steve, I think you and I
4 have got kind of a pit team going here because that
5 particular incidents on the aluminum tank corrosion
6 and its relationship to galvanic corrosion came up
7 with a question I had. Maybe it's out of order, but
8 you might as well take it now.
9 Your galvanic-aging program makes the case
10 for one-time inspection of various structures, and
11 it's based on some algorithm, which quite rightfully,
12 takes into galvanic series and etcetera, etcetera.
13 Has that algorithm been tested against observation,
14 and could it have predicted this particular instance
15 of galvanic corrosion of this aluminum source tank?
16 MR. HALE: But the thing we need to
17 clarify on our galvanic program is our galvanic
18 program is for areas where we have dissimilar metals
19 in treated water systems. I want to clarify that.
20 That's why that's a one-time inspection. We don't
21 anticipate finding galvanic corrosion in the areas
22 that we've identified as part of the galvanic
23 corrosion program. When we have areas where we know
24 we get galvanic corrosion, that's loss of material,
25 when we say we have lost some material, because you

1 get loss of material for other reasons, as well. So
2 that's why the galvanic is more geared to a case where
3 you might have a stainless and carbon and a chemistry-
4 control system. There's not a lot of industry data on
5 whether you get any galvanic corrosion in that kind of
6 a case because, you know, you also need the
7 electrolyte and other aspects of it. So we prioritize,
8 and we identified every galvanic couple in the plant.
9 Now, with regards to this particular
10 instance, I think we've had operating experience, we
11 have seen it, we did not have an active -- I mean, in
12 this case, we had a galvanic, like insulating flanges
13 and that sort of thing, to protect against it because
14 we knew we would get it, but, unfortunately, there
15 were some problems with that couple, such that we got
16 the galvanic and we were designed not to get it. In
17 other words, we didn't have the insulating flanges
18 attached properly, and we actually got -- go ahead,
19 Tony, you can probably --
20 MR. MENOCAL: I'd like to just clarify.
21 The galvanic corrosion that we had in the fueling
22 water tank for Unit 1 was tank bottom, Steve. We do
23 have a galvanic couple on one of the lines coming in,
24 but I believe it was due to external actual galvanic
25 corrosion, something that was in the fill that

1 actually produced a corrosion cell on the tank bottom.
2 MR. HALE: You're right.
3 MR. MENOCAL: And possibly internal, as
4 well. But the corrective action was installation of
5 a liner. But I think the point Steve is trying to
6 make is that where we know we have had, where our
7 tools tell us we have potential for galvanic
8 corrosion, certainly, we would credit a program for
9 doing that. And it may not be, it could be intake
10 cooling water, inspection program, system inspection
11 program. It could be a different system searches
12 monitoring program; it could be a different program.
13 MR. HALE: For example, the salt water
14 system, we don't credit the galvanic corrosion program
15 because we're going to get loss of material from a
16 wide range, including galvanic, so that's included
17 with the loss of material.
18 MR. MENOCAL: But the galvanic corrosion
19 program is for those cases where, merely, the
20 metallurgical tools we had to determine whether we
21 have any significant corrosion rate due to galvanic or
22 not is really we don't anticipate it. We didn't feel
23 we had enough confidence to rule it out, even though
24 we had no operating experience to show that we had it.
25 So it's more a confirmatory program to make sure that,

1 even though we don't feel we have it, that we've
2 actually physically inspected and confirmed that.
3 MR. HALE: And that's to address your
4 question on the one-time inspection. Now let's get
5 back to --
6 MEMBER FORD: Yes, I didn't want to get
7 into the details of this particular incident. It's
8 really kind of a longstanding concern I think many of
9 us have had about what is the rationale for one-time
10 inspections? The experimental, the validity of
11 prediction algorithms say we should inspect this one
12 time. Where is evidence that this methodology is
13 quantitatively correct? Because it's supremely
14 important to me. If you want to have one inspection
15 to go from 40 to 60 years, that inspection better be
16 at the right place at the right time.
17 MR. HALE: Right.
18 MEMBER FORD: And I'm just trying to
19 follow along that line. Maybe you can go into some of
20 the open items I know. Maybe you can discuss that at
21 that time.
22 MR. HALE: Well, the one-time inspection,
23 the way we applied it, what our logic was, one-time
24 inspections are those associated where we don't expect
25 to find aging effects, okay? So I want to make that

1 clear. That's an area that we would not apply one-
2 time inspection unless we don't expect to find aging
3 effects.
4 Now, though we have, in our corrective
5 actions, is if we do find aging effects, then part of
6 the corrective action may be to require additional
7 inspections. So you'll find that embodied in our
8 inspection approaches. And I can tell you, you know,
9 because we're in the implementation stage at Turkey
10 Point, for the galvanic, we did a detailed evaluation
11 of material deltas. What were the three criteria that
12 you used, Tony, in developing the spec? And there
13 were multiple locations --
14 MR. MENOCAL: Yes. What we're doing is
15 we're just trying to limit, since you have hundreds of
16 sites, what we do is systematically identify the most
17 limiting locations based on, again, as you mentioned,
18 the galvanic series, the electrolyte, the contact area
19 between the anodic and cathodic materials. We
20 basically go through and address all those attributes,
21 and then we prioritize so that, what we're inspecting,
22 we have great confidence that it's a limiting and
23 bounding location for all those other areas. And we
24 also try to make sure we address all the different
25 environments as part of that process to make sure that

1 we've got all of the bases covered.

2 MEMBER FORD: I'm sorry for taking up time

3 here, Mario. I think it's an important issue. You

4 said a good word there: bounding condition.

5 Therefore, make sure that your decision algorithm is

6 correct. You must go beyond that bound. You must

7 take into account areas which have corrosion, have

8 undergone the galvanic corrosion, and that's why I

9 asked the question about this particular aluminum

10 tank. Did your algorithm predict that that would have

11 failed? Therefore, your bounding condition has been

12 validated. Do you understand what I'm getting at?

13 MR. HALE: Right. I understand what

14 you're saying. I think because of an operational

15 issue, I'm not sure a galvanic program would identify

16 this. This was an issue between, as Tony was saying,

17 I guess the fill in aluminum tanks.

18 MR. MENOCAL: Yes, I don't remember now

19 whether it was an external material that was either in

20 the bottom of the tank or external. That's what I

21 don't recall specifically, but I know it was, you

22 know, the couple was created because the location

23 where you would not have expected it. Obviously, we

24 have grade-one fill in the tank bottoms, and you would

25 not have expected something to be there either

1 internally or externally.

2 MEMBER FORD: I've made my point.

3 MEMBER ROSEN: Well, I need to summarize

4 a little bit. What I understand from this discussion

5 is that you have an aluminum refueling water storage

6 tank in Unit 1, which has experienced galvanic

7 corrosion on the bottom, either external or internal,

8 I'm not sure which, external. And that you have an

9 aging management program to assure yourselves that

10 this tank will serve its functional requirements

11 through the extended period of operation.

12 MR. HALE: Right. And we had to do that

13 as part of our ASME Section III program. It's

14 actually an ASME required inspection now. In fact, we

15 flagged the coating material in the application as a

16 requiring program, and we identified aging effects

17 associated with it.

18 CHAIRMAN BONACA: I have a question. I

19 don't understand how you apply it. For example, I was

20 looking at the intake cooling water inspection, and,

21 there, you have a lot of small piping that corroded in

22 the past 20 years, and you replaced 75% of it.

23 MR. HALE: Right.

24 CHAIRMAN BONACA: So you still have 25% of

25 the original material that you now replaced with a

1 corrosion-resistant material. Now, in the
2 application, you made the case, and the NRC accepted
3 it, that all you have to inspect now in the future is
4 the connections between the small-bore piping and the
5 large-bore piping. I'm left with the question, you
6 know, a priori or operating experience will tell me
7 that I should inspect, also, the other 25% that I have
8 not replaced. How did you come to the conclusion,
9 from your operating experience, that you don't have to
10 look at it.
11 MR. HALE: Well, we didn't. That's not
12 the conclusion. What we came to is that we could
13 utilize leakage inspection as an adequate aging
14 management program for those nozzles. Our problem is
15 we can't get inside of that pipe. These are small-
16 bore pipes. We can look at the connection, and that,
17 typically, will be worst case. We're using a
18 combination of the crawl-through inspections that we
19 do in looking at this, in addition to periodic leakage
20 inspections externally. And our basis for saying why
21 leakage inspections is acceptable is that it's an
22 open-cooling water system, and we have margin. As a
23 result of our operating experience, where we've gone
24 through replacing these, when we do get a leak, it's
25 not catastrophic. We get a small leak. It will not

1 impact. In fact, we factor in, I believe it's 100 GPM
2 of loss flow, plus another three-quarter inch break,
3 as part of our verification that we can meet our
4 design standards.
5 It's not that we're not looking at them.
6 The case we were building is that leakage inspections
7 is acceptable for this open cooling water system.
8 One of the things I thought we would do is
9 go through what we did with GALL. This was a specific
10 request from Chris Grimes that we do this since the
11 GALL was formally issued, and we tried to accommodate,
12 as best we could, considering where we were in the
13 development of our technical documents.
14 If you'll go to the next slide. Uh-oh,
15 what happened here? Oh, I thought I saw GALL up
16 there. That was my fault. Okay. Why don't we go
17 back and make sure that I covered everything. Okay,
18 go to the next one. We're okay.
19 Okay. In Chapter Three, we grouped
20 components the same way they were presented in Chapter
21 Two. The results are presented in six-column tables.
22 These are consistent with what we had done with Turkey
23 Point. Our basis for the aging effects for the non-
24 Class I are described in Appendix C. And in terms of
25 electrical design features, our medium and high-

1 voltage cable is ledge-sheathed, and we have a lot of
2 outdoor areas in our plant, as opposed to most plants
3 that you look at.
4 Now, for the GALL comparisons. We flagged
5 differences between the component listing in GALL
6 versus our component listing. This was really to
7 avoid or not to get into RAI's related to why isn't,
8 you know, extraction seen in the scope because it's in
9 GALL. So we specifically, in each section, we
10 summarized, you know, any components that were in GALL
11 that weren't in our plant, as well as components we
12 had that weren't in GALL.
13 We also tried to flag, generally, what the
14 differences in materials in internal and external
15 environments. And then we did provide a reference in
16 the six-column table. This was just for information.
17 Where ever we got a match between the component, the
18 material, and the environment. So if you got a match
19 on those three, we provided a GALL reference. That
20 just was for information for the staff.
21 And then probably the biggest aspect of
22 GALL that we utilized, if we could get a good match
23 between our program and what was described in GALL, we
24 took credit for GALL if we had a program that was
25 consistent with it.

1 And this just shows you some examples
2 right out of the application. This is, you know, a
3 summary which shows how we address the deltas between
4 the components in GALL versus our own plant. The next
5 one talks about, you know, how we showed the
6 differences in materials and environments. You know,
7 with regards to GALL, we identified hey, we've got
8 some, you know, like here's the aluminum. We have
9 fiberglass. You know, there were certain things that
10 weren't in GALL that we have from a materials aspect.
11 This is just a sample of the six-column
12 tables. What I was just going to show you here, you
13 know, here's a case where the safety injection tanks
14 were stainless steel. We got a match with GALL, so we
15 provided the GALL reference right there so staff could
16 go to that table and see how we compared with GALL.
17 And then, at the end, we summarized those
18 programs we credited in this particular section that
19 were consistent with GALL, and then we also identified
20 the plant-specific programs.
21 With regards to Appendix C, this, again,
22 was something that we found useful at Turkey Point.
23 The intent here really is any area where you have
24 taken a generic position on aging effects, you know,
25 so you don't go through repeat RAI's at various

1 sections that you have a technical basis for why, you
2 know, that position was taken. We did factor in some
3 of our RAI's and RAI responses from Turkey Point into
4 this section. And in other lessons learned, we pared
5 it down and didn't put as much information as we had
6 before because some of the information has actually
7 caused some confusion in the Turkey Point application.
8 Some of the specific generic discussions
9 with regards to SCC, bolting, high-cycle fatigue,
10 those were some of the items that were addressed here
11 for non-Class I. Again, the RAI's and, again, as we
12 mentioned previously, we followed the EPRI tools and
13 adapted it to St. Lucie.
14 What I'd like to do right now since there
15 was a question raised about phosphates and how they
16 affect concrete, Bruce is going to kind of go through
17 that to talk about that, and then he'll turn it back
18 over to me. So Bruce Beisler, our civil lead.
19 MR. BEISLER: Yes, as Steve said, Bruce
20 Beisler, civil, from FPL.
21 Basically, the staff asked us to address
22 two questions regarding concrete, specifically the
23 concrete below ground water. One had to do with
24 phosphates and how that affects the concrete, and the
25 second one has to do with corrosion of rebar and how

1 that is managed.

2 Tending to the first question on

3 phosphates, during our license renewal process, we had

4 not come across any issues associated with the

5 phosphates in the soil or the ground water affecting

6 our buried concrete, so we said, well, let's go back

7 and take a look at the technical documentation and see

8 if we can find any information regarding phosphates in

9 the technical references.

10 So what I've included on this slide is a

11 list of documents that we went back and took a

12 specific look at just for phosphates, and you can see

13 there we looked at the ACI documents. This isn't even

14 the complete list. This is just what I chose to put

15 on the slide because I think that these are the most

16 likely places where we would have found information.

17 ACI 201 was the Guide to Durable Concrete, 318 the

18 actual building code, 349 the evaluation relating to

19 nuclear plants, and 515 is actually an ACI document

20 regarding water-proofing of below-grade concrete. And

21 it's interesting to note, in this particular ACI

22 document, there is a table, it's table 252, which

23 lists several hundred chemicals and how those

24 chemicals actually affect concrete. Phosphates, as a

25 general topic, was not listed in that table. The only

1 reference was to phosphoric acid, and that reference
2 really only pertained in relation to building a plant
3 where you are processing food products, say like soft
4 drinks, which use phosphoric acid in making the soft
5 drink and how that could affect the concrete. And
6 basically, what it tells you is contact the Food and
7 Drug Administration for appropriate coatings to put on
8 the flow, so that you're not affecting your concrete
9 with your food processing.
10 But in general, there was no limitations
11 on phosphates in the ACI documents that we reviewed.
12 In addition, in the next slide, we looked at the ASME
13 Section III requirements for concrete reactor vessels
14 and containments and found no information there on
15 phosphates. We looked at ASTM standards for the
16 constituent materials for the concrete, the cement,
17 the aggregates, and found no limitations even on
18 phosphates in the constituent materials.
19 We also looked at the EPRI documents that
20 really were involved with license renewal to see if
21 there was any aging effects identified due to
22 phosphates in those documents, and there was none.
23 So having exhausted the technical
24 documents that we had, we contacted one of the Ph.D's
25 at one of our large AE's that we utilize, and we asked

1 the question, you know, why can we find no information
2 in the technical documents regarding how they affect
3 concrete, and he was kind enough to do some quick
4 research for us and kind of gave us a quick write-up
5 on what he was able to find.
6 And he basically told us that phosphates
7 are not very soluble in water in all ranges of pH,
8 which is contrary to what you find with chlorides and
9 sulfates, which are the main culprits in concrete
10 degradation. Those are very soluble, so they are able
11 to penetrate into the concrete, especially lesser-
12 grade concretes and cause degradation.
13 Additionally, he told us that typical
14 ranges of phosphates and soil or ground water in the
15 neighborhood of 500 to a thousand PPM total
16 phosphates, but most of that is fixed, meaning that it
17 cannot be transported to the concrete to cause the
18 degradation.
19 Nearly all the water soluble phosphates
20 are converted to non-soluble shortly after, if they do
21 come into contact with the concrete, shortly after
22 they do come into the concrete, so they're not able to
23 penetrate into the concrete. Of course, the
24 phosphates, in general, are not harmful to the rebar.
25 If there was any effect, it would affect the high

1 alkalinity of concrete. So his conclusion, based on
2 his research that he did, was in support of what the
3 industry technical documents really tell you is that
4 the phosphates are not a contributor to degradation of
5 concrete.
6 One thing I'd like to point out is that,
7 for St. Lucie plant, specifically, we recognize from
8 the very beginning that our ground water was
9 aggressive. Our chlorides are higher than the
10 thresholds, the published thresholds. Our sulfates
11 are higher than the published thresholds, so we
12 recognize that we needed to manage our concrete below
13 ground water from the very beginning, and that's in
14 our application specifically. So we don't feel that,
15 really, the phosphates are even a factor for St.
16 Lucie, but we did want to address the topic
17 generically.
18 And just as a point of reference, you
19 know, in our initial work for St. Lucie, we did ground
20 water analysis, which is documented in our FSAR, and
21 there was no information about phosphates in that list
22 of all the different chemicals that were analyzed. So
23 we specifically went out and had a lab, took a sample
24 of our ground water and had it analyzed, and our
25 ground water actually had less than one part per

1 million of phosphate content. I don't know how
2 significant that is, but that is a fact.
3 MEMBER ROSEN: One of our other members,
4 one of those who is not here right now, Dana Powers,
5 who had concerns about that. Has this summary been
6 provided to Dana?
7 MR. KUO: We had made a presentation to
8 both Dr. Powers and Dr. Ford a month ago, I believe,
9 and, at that time, I didn't hear any more questions
10 from either Dr. Ford or Dr. Powers.
11 MEMBER FORD: Well, my personal concern is
12 for the rebar. Dr. Powers' comments, I think I
13 remember, were related to some observations that he
14 had had of phosphates affecting concrete fragility,
15 etcetera. Obviously, he has not seen this particular
16 compendium of things I think he should see.
17 MR. KUO: At the time when we made the
18 presentation to both of you, we didn't have the
19 content of phosphate at the St. Lucie. So that was
20 one request that was made. For this subcommittee
21 meeting, we need to address that and see if phosphate
22 content --
23 MEMBER FORD: And that's very appropriate.
24 I just think that Dr. Powers should see this.
25 MEMBER ROSEN: Maybe we can make sure the

1 staff, our staff gets the material then.

2 MR. KOBETZ: The paper that the Ph.D.

3 prepared for you, is that something that we could get

4 a copy of and prepare --

5 MR. BEISLER: Well, it's not a published

6 paper, so it's just something that he kind of threw

7 together very quickly for us, did some quick research,

8 and actually contacted some university professors to

9 get some input for the document.

10 MR. KOBETZ: Okay. You may consider

11 trying to provide something prior to the full

12 committee meeting. It might shorten up discussions in

13 this area.

14 MR. HALE: I think one point, when I saw

15 this question, was I don't think it becomes an issue

16 unless you're trying to show that your water is not

17 aggressive. You know what I mean? Or the discussion.

18 In our case, you know, we knew immediately that we had

19 aggressive ground water, so the need for sampling and

20 this sort of thing, you know, we knew we were going to

21 have to address aging effects. Whereas, if you're

22 taking the position where you're relying on chemistry

23 to establish that you have non-aggressive ground

24 water, then I can where this question would be at

25 issue.

1 MEMBER FORD: It just puzzles me that Dr.
2 Powers has some very -- we're speaking for him in
3 absence -- had some very positive viewpoints on the
4 affect of phosphates on degradation of concrete, per
5 se. It just puzzles me that we now have a long list
6 of references saying, hey, there's no reference to it.
7 There's nothing, say, a graph, a cut-off point between
8 fragility and phosphate concentration.
9 On the rebar, this is the one I've been
10 interested in, I was at an ACI meeting a couple of
11 weeks ago. I very specifically went to the concrete
12 corrosion, rebar corrosion, which was authored by
13 somebody at the University of Florida, so I'm going to
14 be interested to see what you say about this.
15 MR. BEISLER: Okay. Well, we haven't
16 reviewed that document, but I'll tell you what we did
17 find.
18 MR. KUO: If I may say something else, I
19 believe when we talked to Dr. Powers, I think he
20 agreed that this, in general, phosphate is not a
21 concern. However, his concern is really to states,
22 Texas and in Florida, where the weather chemistry
23 contains a high percentage of a phosphate. I believe
24 the applicant did that. You just said the phosphate
25 content is one in a million?

1 MR. HALE: 0.15.

2 MR. KUO: 0.15? Okay. So that is
3 actually, I think, is outside the range. You later on
4 will hear staff's presentation, but that's, in
5 general, I think -- and like Steve just mentioned
6 that, you know, if we rely on water chemistry for
7 concrete underground with ground water presented, then
8 I think that would be a concern. However, they do
9 recognize that their water is aggressive nature, and
10 they provided an aging management program.

11 MR. BEISLER: All right. With regard to
12 the question about corrosion of rebar, the first thing
13 we looked at is, really, how can you protect your
14 rebar, and that is with high-quality concrete. So we
15 looked at the ACI documents and what they recommend
16 for concrete in this environment, and what I've
17 included on this slide is some of the facts.
18 Basically, the ACI 201 for durability of concrete
19 recommends a water/cement ratio less than 0.45, and
20 St. Lucie structures their exposed to ground water,
21 all specified, less than or equal or 0.44.

22 The ACI document recommends the ASTM C150
23 type five cement. In the case of St. Lucie, this
24 cement was adopted by the ACI in 1977, and, of course,
25 the St. Lucie specification for concrete pre-dates

1 that timeframe. And what we did use was the type two
2 cement, which was the preferred cement at that time
3 for sulfate resistance. Also, the ACI document
4 recommends that we use an appropriate air entrapment,
5 and for St. Lucie, the range of air entrapment was two
6 and a half to nine-percent, and that's basically based
7 on what size aggregate is used in the concrete. But
8 all of that meets the recommendations of the ACI
9 document.
10 In addition, the ACI document recommends
11 moist curing for seven days, and St. Lucie required
12 seven to 14 days, so we met or exceeded that
13 requirement.
14 In addition, the ACI document recommends
15 high-quality constituent materials, including
16 aggregates per the ASTM C33, cement, ASTM C150, and
17 very clean water, and all those are included in the
18 St. Lucie concrete.
19 In addition, the ACI document recommends
20 one and a half or, preferably, two inches of concrete
21 cover. St. Lucie structures all have a minimum of
22 three inches, and, in fact, the structures that are
23 exposed to ground water have even more cover, in some
24 cases up to five or six inches of cover, which is
25 specified on the individual drawings for the specific

1 structures.

2 Concrete exposed to salt water should have

3 a 28-day strength of, at least, 5,000 PSI. For St.

4 Lucie Unit 1, the specification required 4,000 PSI,

5 but the actual strengths of the concrete breaks, in

6 general, were all over 5,000 PSI. So even though

7 specification may have only required four, the actual

8 concrete strength was greater.

9 In addition, the code --

10 MEMBER ROSEN: Is that a universal

11 statement? You said "all."

12 MR. BEISLER: Well, all that we could

13 find, but we're not certain that we could find every

14 single concrete break, so I can't say that there

15 wasn't one that might have been less than 5,000. But

16 in general, and even our FSAR has that statement, the

17 breaks were greater than 5,000. But personally, I

18 didn't go and pull all the break records to confirm

19 that it is 100%, so I can't say "all," I cannot say

20 "all."

21 MEMBER ROSEN: In general, you said.

22 MR. BEISLER: In general, yes. And that's

23 pretty typical, quite frankly, because the ACI codes

24 have certain requirements, probabilistic requirements

25 that, you know, if your specification is 4,000, that

1 you're going to exceed that 4,000 to reduce the
2 probability that you could have one that would be less
3 than 4,000. Commercially, that's done, as well.
4 MEMBER FORD: Everything you've mentioned
5 is good news so far, but one item that concerns me the
6 cover of the steel one and a half to two inches. Now,
7 when I looked up at Turkey Point, I looked up on the
8 containment, and I saw big bolts with knots on them,
9 and I asked the tour guide, and they said, "Oh, those
10 are the pre-stressing wise." Now, they seem to me to
11 be exposed. The steel will be intention 5,000 PSI or
12 whatever the equivalent would be. Is that pre-stress?
13 In that particular instance, when I was looking up at
14 the containment building, was, in fact, that the pre-
15 stressed --
16 MR. HALE: Yes.
17 MEMBER FORD: -- and was it exposed to the
18 environment?
19 MR. BEISLER: Well, the pre-stress wire,
20 basically, what you have is you have the wire that's
21 in the sheath, which is contained inside of grease,
22 which is a corrosion-protecting grease, okay? And
23 then at the two ends of the pre-tension cable, you
24 have the anchors, and the anchors are the steel that
25 connects and, basically, places that intention. Those

are exposed to the atmosphere, but they are painted, okay? The steel is painted for protection, and then you have, basically, the end of the pre-stressing material.

MEMBER FORD: Now, am I making too much of this? Now we're relying on just the paint over the nuts?

MR. HALE: No, no, there's a whole program, there's a whole program associated with the tensioning. And there are no, correct me if I'm wrong, Bruce, but there are no tendons exposed to ground water.

MR. BEISLER: That's correct.

MEMBER FORD: Okay. In the interest of time, I think we can move on.

MR. HALE: Yes, I apologize for taking so long.

MR. BEISLER: No, no, no.

MEMBER FORD: Unless the other members want to keep going on this concrete business, I'll probably bring it up in the open questions because it was opened in one of the opening questions.

MR. HALE: Well, one thing Bruce did want to summarize is what we have seen and what we actually do as part of the program.

1 MR. BEISLER: The program does include
2 visual inspections of exposed interior and exterior
3 surfaces of the concrete, and we look for signs of
4 degradations, specifically corrosion of the rebar, in
5 which case you would see cracking, rust staining
6 possibly, and spalling, although, usually, it never
7 gets to that point.
8 For our buried concrete structures, our
9 program now includes doing inspections of buried
10 structures, which are excavated for whatever reason.
11 And although it wasn't part of the formalized program
12 at the time it happened, we have done that in recent
13 years, and I just cited a few examples here of
14 situations where we did do excavations, we did inspect
15 the concrete, and we saw no signs of degradation. And
16 those are listed on the slide.
17 MEMBER ROSEN: What is the 2002 CPS
18 replacement mean?
19 MR. BEISLER: That's cathodic protection
20 system, and, basically, what happens is the anodes,
21 after a certain period of time, are exhausted, and we
22 had to install new anodes, in which case we did
23 excavations adjacent to the structure, which allowed
24 us to see varied portions of the structure.
25 MR. HALE: And again, I apologize for

1 taking too long. I know I've taken more than my
2 allotted time here, so I'll try to get through the
3 rest of what I have here.
4 With regards to the aging management
5 program, for each aging effect requiring management,
6 we identified aging management programs, and we did
7 that on a component basis in the six-column tables.
8 When you get into Appendix B, we provided the 10-
9 attribute evaluations for the plant-specific programs,
10 and then, for those programs, where we specifically
11 indicated we were consistent with GALL, we discussed
12 operating experience and demonstration, and we also
13 had a brief description and a statement indicating
14 that we were consistent with GALL.
15 Supporting that is an evaluation on-site
16 which goes through an assessment of the GALL
17 attributes versus our own program attributes, as well
18 as the general program description and the criteria
19 for the program. Those are documented in what we call
20 our program basis documents on-site.
21 With regards to the application, we had
22 presented the quality-assurance requirements, which we
23 committed to be consistent with the staff on quality-
24 assurance requirements. We included that in Appendix
25 B in section II.

1 We had two categories of aging management
2 programs. Our numbers may be slightly different than
3 what's with the NRC because of the way we broke down
4 the chemistry program. But essentially, we had 16
5 existing programs. We were able to show that nine of
6 those were consistent with GALL, and then we have
7 seven plant-specific. And in the new category, we had
8 one GALL, and the other six were plant-specific.
9 This is just a summary of the existing
10 aging management programs which were consistent with
11 GALL. Section XI, all three, you know, the mechanical
12 areas and in the structural areas: the Borflex
13 surveillance program; our boric acid waste and
14 surveillance program, although we do include more
15 systems than were in GALL, in other words it's more
16 extensive. We were able to show it was consistent.
17 Here's where we might see the difference
18 in the way the NRC, the staff will present the
19 chemistry program. We called it one program with
20 subprograms, and they called them each individually a
21 program. But we're able to show that two of our
22 chemistry programs were consistent with GALL. This
23 was in the primary side and the secondary side and
24 closed cooling water. But just the way we structure
25 our fuel oil chemistry program, you know, some aspects

1 of it, in terms of visual inspections and stuff, are
2 covered by the PM program, and the chemistry is
3 covered by other areas, so we weren't able to show
4 that. So that is plant-specific. And our EQ program
5 is consistent with GALL.
6 MEMBER LEITCH: Steve, I had a question
7 about whether you're going to be able to fully comply
8 with the new NRC order-related to vessel head
9 penetration inspections. I know there's a plant that
10 I think is similar to St. Lucie that is now having
11 some difficulty fully complying with that order
12 because of, as I understand it, rather than the more
13 typical arrangement, this plant and St. Lucie also
14 have guide sleeves or thermal sleeves in the CRDM
15 penetrations, and that makes it difficult for them to
16 get the required data. I just wondered if you've
17 dealt with that problem yet? Are you going to be able
18 to do those inspections?
19 MR. HALE: We have the guide sleeves on
20 Unit I, and, in anticipation of that question, brought
21 the 30-day inspection report that was issued after we
22 did 100% visual -- it's documented. You can have it.
23 What we found --
24 MEMBER LEITCH: This isn't enough for
25 everybody to read.

1 MR. HALE: But that is our report that we
2 submitted. We did 100% visual and 100% UT on Unit 1
3 last refueling outage, and that was the 30-day report
4 to summarize that. There is a table in there that
5 looks at UT inspections. If you look at the head
6 penetration, we broke it into four areas. We have the
7 penetration below the weld, what we call the weld
8 area, the root, and then two inches above the weld.
9 What we're able to do is we've got almost 100%
10 coverage UT in the area above the weld and the root
11 area. As you come out, our problem was one of there
12 was too much slop in the thermal sleeve relative, so
13 you couldn't get the -- the probe has to take two
14 directional, you know, to insert it, it has to go this
15 way and up in, and right at the bottom, you had a hard
16 time getting the probe flat on the actual nozzle.
17 You'll see that in there, though, even in
18 those areas where we couldn't get full coverage, we
19 were still getting quite a large sampling of the
20 information there. But it's all in that report, and
21 I think you'll find it interesting.
22 MEMBER LEITCH: But this pre-dated the
23 order, right?
24 MR. HALE: It did, it did, but it gets
25 into details of the specific issue you're talking

about. Certainly, if we are required to do this, and we had two cases where we actually moved the sleeve. But I think what you get is how extensive the inspections were and how, you know, there was a pretty good coverage, although we couldn't get 100% in all areas, we did get a good coverage on all penetrations. And in the critical areas, we got almost 100%, which is the weld root and the two inches above. The justification for not full coverage there is, if you do get a crack, what you're concerned about, in terms of circumferential, you know, rod ejection, that sort of thing, is in that weld root area.

But that's all in the report, and I think you might find it interesting.

MEMBER ROSEN: I'm interested in what the overall results of the inspection were.

MR. HALE: We had no indication of leakage, and we had no indications of cracking on Unit 1.

MEMBER ROSEN: And Unit 2 is yet to be done?

MR. HALE: It's getting ready to be done. They outage is next week or the following week, something like that.

MEMBER LEITCH: That's Unit 2; I didn't

1 hear that.

2 MR. HALE: Yes, Unit 2.

3 MEMBER LEITCH: And Unit 2 doesn't have

4 these sleeves?

5 MR. HALE: Right, right. So this is only

6 a Unit 1 issue.

7 MEMBER LEITCH: You would have some

8 problem then complying with the order on Unit 1. I

9 mean, I think what you're saying is you comply with

10 the intent of it, you're confident that there's no

11 problems, but what I'm saying is complying with the

12 specific detail of the order on Unit 1 would be a

13 problem.

14 MR. HALE: And if the NRC raises that as

15 an issue, and they can't accept what we've done here,

16 we would have to comply with order, whatever would be

17 required. If push comes to shove, we could actually

18 remove the sleeves, but, you know, I think all of us

19 in the industry are considering head replacements and

20 things of this sort, so, you know, that's also on the

21 front end, as well.

22 MEMBER LEITCH: You have not yet made a

23 decision in that regard?

24 MR. HALE: Not with regard to St. Lucie.

25 Turkey Point, we are going to replace the heads in

2004 and 2005, even though we haven't seen any indication of leakage.

MR. KUO: Dr. Leitch, staff has some comments on this issue, and Stephanie Coffin, she is a session chief in the Materials Engine Branch.

MS. COFFIN: I just want to make clear what the process is for this. We issued the orders. I believe St. Lucie has asked for relaxation of those orders based on technical document that Steve talked about, that's under review, and we have no, it's pre-decisional right now in terms of what our position is on that.

MR. HALE: I guess my point was whatever the NRC determines we have to do, certainly, we'll have to do under the order. But I think when you look at that, you can see how extensively we have been able to cover from the UT inspections, with exception of certain areas.

MEMBER LEITCH: Okay, thank you.

MR. HALE: Existing programs with GALL, the FAC program, flow accelerated corrosion, was consistent. We did find an area here where we wanted to include enhancements. This is not to meet GALL. This enhancement was just something we felt we needed to do in terms of inspections on some of the small-

1 bore lines and putting that into our FAC program.

2 Steam generator integrity program, this is

3 consistent with GALL, but, again, this is a program

4 where we're doing more than what the GALL requires.

5 However, we were able to show that we were consistent

6 with it.

7 CHAIRMAN BONACA: Or small-bore piping, so

8 have you agreed with staff that you will look for

9 susceptible locations, that you would not use --

10 MR. HALE: That particular one was related

11 to Class I, which is not related to FAC. This was,

12 you know, where you have safety-related lines, trapped

13 lines, things that come off, like, the main steam

14 lines and this sort of thing, where, you know, if the

15 trap is not working or, you know, they can actually

16 get cold, so you actually get corrosion on the

17 external surfaces, as well, but we're actually using

18 our FAC program, what we call computed radiography,

19 where we can actually inspect both the outside and

20 inside of the pipe as part of our FAC program.

21 MEMBER WALLIS: Do you get water hammers

22 in those when they get cold?

23 MR. HALE: No, it just, you know, from

24 sitting there, the traps are interesting because if

25 they sit there closed, then the water cools off. But

1 if they blow through, then you've got continual flow,
2 and you got a flow accelerated corrosion issue. So we
3 don't get water hammers with them because the way a
4 trap works, you know, once you get a fluid level in
5 it, it's supposed to open and let the fluid pass
6 through.
7 MEMBER WALLIS: But if you've got
8 accumulation of cold water, you can get some rapid
9 condensation there.
10 MR. HALE: Yes. What I'm saying is cold
11 is relative. What we found, this is an operating
12 experience issue, what we found at Turkey Point and at
13 St. Lucie is we've had problems with some of these
14 lines primarily due to external corrosion because
15 they're insulated, and if they drop below a certain
16 temperature, you can actually get water on the outside
17 surface to actually start corroding the lines.
18 We credit our FAC program because, as part
19 of our FAC program, we do what we call computed
20 radiography, which, up to about eight inches, you can
21 actually take a radiographic picture that can actually
22 show you the outside surface of the pipe, as well as
23 the inside surface of the pipe. So you can actually
24 look at both factors at one time. And so we put that
25 in there.

1 Existing plant-specific aging management
2 programs, our alloy 600 program, fatigue monitoring,
3 fire protection, intake cooling water inspection, and
4 RPM program, we did have some enhancements we
5 recommended for the PM program in terms of getting
6 more specific with regards to certain components and
7 what you look for.
8 Again, to continue with our existing
9 plant-specific, reactor vessel integrity program is
10 plant-specific, and our systems and structures
11 monitoring programs. And then this is the area where
12 we've expanded to include certain enhancements. It's
13 probably a good idea to speed me along here.
14 Our new aging management programs, the one that is
15 consistent with GALL, is related to thermal aging and
16 embrittlement. Our new plant-specific programs, we
17 have a storage tank cross tie between Unit 1 and Unit
18 2. We have a specific program for that. Our
19 containment cable inspection program was a new program
20 that we committed to with the staff, and then our
21 galvanic corrosion susceptibility inspection program.
22 We have a program specifically looking at
23 certain areas where we've had pipe-wall thinning. Our
24 reactor vessel and internals inspection program and
25 our small-bore Class I. This is the one, Dr. Bonaca,

that you were referring to on whether we're using risk --

MEMBER ROSEN: On the reactor vessel internals inspection program, am I correct in recalling that St. Lucie had some damage, extensive damage to core barrel?

MR. HALE: Yes.

MEMBER ROSEN: I am correct?

MR. HALE: Yes, yes. In fact, we had quite a bit of dialogue with the staff on our barrel repairs. There was a TLAA; that's flagged in the application, which discusses that. We had to re-evaluate, you know, the repair includes patches and plugs and that sort of thing, but we actually had to remove the thermal shield.

MEMBER ROSEN: And so this reactor vessel internals program deals with watching how that repair performs over the extended license term?

MR. HALE: No, actually, what this program is is what we do over and above Section XI. We're already committed under Section XI to do inspections and follow-up with regard to those barrel repairs. So this program is a program that's been instituted to go over and above what we do under Section XI, and it addresses some of the more research-type of things,

1 like, you know, what's the effect of radiation
2 embrittlement, radiation-assisted primary water,
3 there's a whole series of items right now that are
4 being investigated and looked at under the MRP.
5 MEMBER ROSEN: I want to come back to the
6 repair program. That was a fairly extensive repair,
7 as I recall.
8 MR. HALE: Yes, yes.
9 MEMBER ROSEN: And you're saying that
10 that, the performance of that repair over the extended
11 life of the license now would be controlled by what
12 you do under the code?
13 MR. HALE: Two aspects: there's a TLAA and
14 a calculational assessment, which is included in the
15 application, plus ongoing visual inspections of the
16 repair areas as part of the Section XI program. So
17 the time dependent aspects of the design with regards
18 to radiation, embrittlement, and fatigue are
19 addressing the application from a calculational
20 standpoint, but, in addition to that, we are doing
21 specific inspections that were required as part of
22 that repair resolution as part of Section XI.
23 CHAIRMAN BONACA: And the TLAA takes you
24 to 60 years?
25 MR. HALE: Right, it does. In fact, we

1 even submitted the proprietary calculation to the
2 staff for their review and independent assessment of.
3 CHAIRMAN BONACA: Those were expansion
4 patches?
5 MR. HALE: Yes, yes. If you look at it,
6 it's like a cylinder with a bottom on it and a doubled
7 edge. You actually pressed it in to where you sprung
8 the beveled edge, and then you expanded it inside of
9 the core support barrel.
10 MEMBER ROSEN: And the staff's
11 presentation of PT, are you intending to comment on
12 that?
13 MR. DUDLEY: No, we did not include the
14 TLAA on core barrel repair as part in preparation for
15 it, but we can provide you additional information on
16 the review that was done.
17 MEMBER ROSEN: I would be interested in
18 the short summary, at least, of that review.
19 MR. KUO: We'll do that.
20 MR. HALE: Okay. With regards to TLAA's,
21 metal fatigue, certainly, is one area that is
22 addressed. We were able to demonstrate at St. Lucie
23 that our 40-year cycles are bounding for six years.
24 The approach we took to environmentally-assisted
25 fatigue was similar to what we were able to work

1 through and agree to with the staff at Turkey Point.
2 With regards to EQ, we did incorporate some lessons
3 learned from the Turkey Point review. Where cycle
4 aging was an item that the NRC requested that we
5 address at Turkey Point, we've incorporated that into
6 our St. Lucie assessment.
7 There was a difference of opinion on how
8 you classify the EQ TLAA's, so we adopted what the
9 staff had recommended that we utilize. And then our
10 information with regards to what we do for temperature
11 and radiation monitoring, we put into the application
12 to address RAI's that we had gotten at Turkey Point.
13 Other TLAA's: containment penetration,
14 fatigue, rack and cooling system piping, leak before
15 break, crane fatigue. This is the core support barrel
16 repair TLAA that we were speaking of. Alloy 600
17 instrument nozzle repairs. This is another area where
18 there's a specific TLAA associated with it. We did
19 not find any time-bound license exemptions as part of
20 our review process.
21 In conclusion, the aging management
22 programs at St. Lucie, we feel we have demonstrated
23 they'll manage the aging effects, so the intended
24 functions will be maintained consistent with our CLB.
25 For all the TLAA's for St. Lucie have been evaluated

1 and shown to be acceptable for the extended period of
2 operation.
3 That was the extent of my presentation.
4 Again, I apologize for going over. Any other
5 questions for us?
6 CHAIRMAN BONACA: So far as the alloy 600
7 instrument nozzle repairs, the staff can talk about
8 that. Okay.
9 MR. HALE: We've brought some technical
10 details, as well.
11 CHAIRMAN BONACA: Yes, I would like to
12 review a little bit that information there, and I
13 think we'll do it when the staff does the
14 presentation. And then the applicant can help us with
15 that. Okay. Thank you very much for your
16 presentation.
17 MR. HALE: Yes. Thanks for your
18 attention.
19 CHAIRMAN BONACA: If there is no
20 additional questions, at this point, we'll take a
21 break, and we'll start again at a quarter of 11.
22 MR. DUDLEY: If visitors want to leave the
23 floor, they need an escort, so let us know, and we'll
24 try to find you an escort.
25 (Whereupon, the foregoing

1 matter went off the record at
2 10:27 a.m. and went back on the
3 record at 10:46 a.m.)
4 CHAIRMAN BONACA: Okay. Let's get back
5 into session. And now we have the staff presentation.
6 MR. DUDLEY: Thank you. Good morning. My
7 name is Noel Dudley, and I'm the project manager for
8 the St. Lucie license renewal application review.
9 With me at the table are Tilda Liu, the back-up
10 project manager for St. Lucie, and Jim Medoff, who
11 reviewed the issues related to materials.
12 As an overview of today's presentation, I
13 plan to summarize the agenda, outline the review
14 conducted by the staff, note the changes to the
15 application resulting from the staff's review, and
16 present the status of the revised oversight process
17 and recent events.
18 The staff will present the status of the
19 open and confirmatory items and summarize the scoping
20 and screening methodology and the scoping and
21 screening results. After lunch, the staff will
22 present the aging management program inspections;
23 concrete aging, as requested by the ACRS members, this
24 will be the staff's review of the information
25 presented by the applicant this morning; aging

1 management programs and four of the time limited aging
2 analysis, which the ACRS has requested.
3 The staff will conclude its presentation
4 by explaining the Interim Staff Guidance process and
5 will provide the status of the identified Interim
6 Staff Guidance issues.
7 St. Lucie Nuclear Power Plant Units 1 and
8 2 are combustion engineering plants with large dry
9 containments. Unit 1 is seven years older than Unit
10 2, which resulted in some design differences between
11 the units.
12 The St. Lucie process and programs which
13 are associated with license renewal are similar to
14 those used at Turkey Point. The differences between
15 the designs of the combustion engineering plant and
16 the Westinghouse plant introduces some unique aging
17 management and time limiting aging analyses.
18 When the staff received the St. Lucie license renewal
19 application, the staff reviewed the application in
20 detail and developed the draft request for additional
21 information concerning verification, clarification,
22 and explanation of information in the application.
23 After meeting and discussing the draft RAI's with the
24 application, the staff issued request for additional
25 information that was required for completing the

1 review, and it was not on the docket. The applicant
2 than submitted responses to these RAI's.
3 In some cases, additional meetings were
4 held to discuss the draft responses. As a result of
5 these meetings, the applicant revised the draft RAI
6 responses before they were submitted to the NRC. On
7 the basis of the information in the license renewal
8 application and in the RAI responses, the staff
9 prepared the SER with open items, which you've
10 received and were reviewing today or discussing today.
11 Since issuing the SER with open items, the staff has
12 continued its discussion with the application to
13 resolve the open items. Once all the open items and
14 confirmatory items are resolved, the staff will issue
15 a revised SER, which will provide the basis for
16 issuing the license renewal.
17 As the slide illustrates, the staff and
18 the applicant have expended significant time and
19 effort in this review process. The applicant used the
20 lessons learned from its Turkey Point license renewal
21 application when they prepared the St. Lucie
22 application. About 70 fewer RAI's were issued during
23 the St. Lucie license renewal application review as
24 were issued for the Turkey Point review.
25 In response to Dr. Ford's questioning

about the reduction in number of RAI's, in some cases, RAI's were issued to get needed documentation of plant-specific information, even though the process had already been reviewed and approved at Turkey Point. So that's some of the reasons for the RAI's is to get that specific information to fill out an accepted position.

As a result of the NRC staff review, new components or commodity groups were identified and subject to an aging management review. Of these, about 75 components required aging management programs. In response to one RAI, the applicant created a new aging management program.

As it turns out, there were about 79, of the 79 new components or structures within scope, about 70 of them were in response to the station blackout II over I and the fan and damper housing Interim Staff Guidance.

Let's see. Slide seven. The NRC staff conducted one audit and two inspections to verify information contained in the application were in responses to the RAI's.

There are 11 open items identified in the SER with open items. The staff has reached resolution on all of these items, and now I will go through each

1 of the items and explain why the staff accepted the
2 position presented by the applicant.
3 The first open item resulted from
4 scheduling issues associated with the SER with open
5 items being issued prior to the aging management
6 program inspection report. The aging management
7 program inspection was completed a week before the
8 staff issued the SER with open items, and
9 documentation of the reports was not issued until
10 March 7th, 2003.
11 Since several of the sections in the SER
12 relied on results of the AMP inspection, we could not,
13 we had to go back and verify when the inspection
14 report came out and whether the supporting information
15 was still valid. The staff has determined that
16 inspection findings support the conclusions in the
17 SER, and this item is resolved, and the staff will
18 revise the appropriate sections of the SER.
19 The second issue, the staff questioned the
20 management of wall thinning due to internal corrosion
21 of small-bore piping in the fire-protection system.
22 For previous applications, the staff accepted aging
23 management programs that included volumetric
24 inspection of these lines. The fire protection system
25 is supplied for city water, and the applicant's

1 monitors internal piping conditions via pressure
2 tests, leakage tests, and identification of excessive
3 corrosion products during flushing of the systems.
4 Past operating experience has not
5 identified any degraded conditions of the internal
6 surfaces, and during recent modifications of the
7 system, the applicant obtained ultrasonic pipe wall-
8 thickness measurements on stagnant portions of the
9 system. The measured wall thicknesses were
10 approximately nominal.
11 Based upon a nominal wall thickness in the
12 measured wall thicknesses, the applicant determined a
13 worst-case corrosion rate might have occurred over the
14 last 24 years of operation. They then used the worst-
15 case corrosion rate and calculated the pipe wall
16 thickness at the end of the period of extended
17 operations and found the wall thickness would be
18 greater than the ASME B31.1 code requirements for a
19 minimum wall thickness. So based on the volumetric
20 measurements and the corrosion rate calculations, this
21 item was resolved.
22 CHAIRMAN BONACA: So you still will rely
23 on leakage?
24 MR. DUDLEY: Not in this case.
25 CHAIRMAN BONACA: Well, I mean, you're

1 making a projection that there will be no leakage
2 happening because there is assurance from this
3 projections that the nominal thickness or some level
4 of thickness will still be there. But are there going
5 to be additional inspections, volumetric inspections?
6 MR. DUDLEY: Yes, there will be continual
7 inspections looking at the pressure, the flow, and the
8 check for corrosion products during the flush.
9 CHAIRMAN BONACA: Which is the plan they
10 have.
11 MR. DUDLEY: That's correct.
12 CHAIRMAN BONACA: But there will be no
13 further volumetric inspections?
14 MR. DUDLEY: Jay, can you help me out
15 here?
16 MR. HALE: Let me, if I could, you know,
17 we have a fire protection program which looks at fire
18 protection systems. The issue with regards to
19 ultrasonic as related to wet pipe systems that are
20 pressurized all the time, like fixed sprinkler systems
21 and that sort of thing, if you get any leakage, you
22 would get indication that you had a problem, and you'd
23 have to correct that under the fire protection
24 program.
25 This was a case of trying to characterize,

1 you know, whether you're getting any internal
2 corrosion, which may affect sprinkler capability,
3 okay? And we felt that, by looking at the pressure
4 boundary, also looking at volumetric inspections
5 provided a position as to why we didn't need to do
6 volumetric inspection. We still have quite a bit we
7 have to do under the fire protection program, in terms
8 of monitoring fixed systems, testing pumps, ensuring
9 that we get flows at the far end of the system and the
10 right pressure. So I wanted to clarify that.
11 MR. DUDLEY: Yes. And Jay Rajan was the
12 reviewer for this section, and I'd like him to explain
13 what he was basing the acceptance of the applicant's
14 position on and why this is acceptable to the staff.
15 MR. RAJAN: As pointed out, we based our
16 acceptance primarily on the flushing pressure testing
17 and performance testing, but this was one of the areas
18 where the flow testing was not being conducted, so we
19 questioned the license how do you verify the
20 acceptability of the wall thickness in those areas. So
21 in some of those smaller lines, they made a one-time
22 inspection and based a corrosion rate, excuse me,
23 estimated a corrosion rate based on the performance of
24 that line and projected it out. It turns out that
25 there was sufficient margin, and we accepted that on

1 that basis.

2 CHAIRMAN BONACA: Okay. The reason why I

3 raise the question was that I don't have any problem

4 with this kind of process that you used. My only

5 problem, I guess, is if I think about St. Lucie 2 has

6 only ran for 20 years, not even, so much of it's life

7 is in the future, and we're making a judgment about

8 this program 20 years before we talk into license

9 renewal. I would have liked to see some kind of

10 statement that says we will re-evaluate the piping

11 system and look at it, you know, just a reasonable

12 approach. I'm not asking for inspection and project,

13 at that point, whether or not the experience over the

14 last 40 years tells us that we have to do anything

15 more or less in the next 20. It would give me more

16 comfort than now. Even 20 years of operation and

17 before the next 40-plus, we are already making a

18 commitment to all that we're going to do.

19 MR. HALE: Well, I think that what's

20 important here is that our fire protection program

21 requires multiple surveillances of all kinds. This

22 was a specific issue related to the internal condition

23 of fixed pipes related to sprinkler system. Unit 1

24 fire protection system has been there quite some time,

25 27 years, and, essentially, what we were able to -- in

1 our water for fire protection, although we classified
2 it as raw water, is domestic water. The water we use
3 in our fire protection system is basically the water
4 that comes out of your faucet. So our feeling was do
5 we need to have a continuing program of ultrasonics to
6 supplement what we already do, which is quite
7 extensive under the fire protection.
8 MR. MENOCAL: I wanted to add one thing,
9 if I could, too. Even though we did a corrosion, as
10 was mentioned, what we found when we measured the wall
11 thickness was that it was essentially nominal. Now,
12 we didn't have baseline data, so we don't know what
13 the original wall thickness was, so we, very
14 conservatively, added on manufacturer's corrosion
15 allowance, and, basically, the corrosion rate was
16 based on using the high end of the corrosion
17 allowance, which, normally, you don't get that in the
18 pipe. The manufacturers are going to be on the low
19 end, but we added that on to it. It's a very
20 conservative corrosion rate. I don't believe we've
21 seen any significant corrosion at all.
22 CHAIRMAN BONACA: Fire protection program
23 would require, anyway, testing and inspections.
24 MR. DUDLEY: The real question that the
25 staff was dealing with here was there was no

1 expectation that there would be corrosion in the
2 stagnant lines. There was no way to verify whether it
3 had been occurring or not, besides the flush, and
4 whether, after 27 years of operation of the system,
5 getting a volumetric measurement of the wall thickness
6 and actually opening up and taking a look at the
7 internals of the pipe and determining that there was
8 no identifiable corrosion in the pipe, whether that
9 could be used as a one-time inspection to verify the
10 applicant's claim that there was no reason for
11 corrosion to occur in the pipe and use that as a one-
12 time inspection, which would not require any further
13 evaluations or inspections of volumetric proportions
14 or opening your pipe up again. So that was what we
15 were really struggling with was whether that was
16 acceptable to be used as a one-time inspection, and we
17 decided that yes, it would be.
18 CHAIRMAN BONACA: Let me ask one question
19 now. Given this issue is closed, prior to entrance in
20 the license renewal, the NRC would not look at this
21 issue again.
22 MR. DUDLEY: That's correct. It now
23 becomes an operating plant issue that, if they do have
24 an operating experience of internal corrosion or a
25 leaking pipe caused by internal corrosion, then,

1 through the correction action program, the licensee
2 would be required to develop an aging management
3 program to control the now identified aging management
4 effect.
5 CHAIRMAN BONACA: But the logic, in that
6 case, that's always true of anything, so we didn't
7 need license renewal. Logic, typically, my judgment
8 is that they don't want to bring the component to
9 failure because that could affect the functionality of
10 the system. That's why we have license renewal, so
11 you have sufficient confidence that the testing done
12 for the fire protection system will, in fact, assure
13 functionality, even though there isn't any specific
14 AMR being applied for that function there. I guess
15 that's what we have to rely on.
16 MR. DUDLEY: That's correct.
17 MEMBER WALLIS: Your second bullet,
18 minimum is the wrong word. The minimum loss of
19 material would be zero because minimum is the lowest
20 possible. What you mean is they were unable to detect
21 any loss of material, the pipe size of nominal. They
22 didn't really measure loss of material.
23 MR. DUDLEY: No, they didn't. It was
24 nominal.
25 MEMBER WALLIS: The pipe size was nominal;

1 that's the conclusion you already have.

2 MR. DUDLEY: That's correct. And where

3 they drive the corrosion rate was the uncertainty of

4 what nominal is, the plus and minus of acceptability.

5 MEMBER FORD: And do I understand it then

6 that, just to follow on Mario's question, I expect it

7 in a stagnant line, which is, essentially, de-aerated

8 over time; there will be very little general

9 corrosion, and your inspections have confirmed that.

10 If you had localized corrosion because of copper

11 getting into the system or whatever it might be, that

12 would identify itself in a leak, which would

13 automatically be found. That is not a safety issue?

14 That's a question. That, therefore, would not be a

15 safety issue; is that correct? If you find a leak,

16 you have to do something about it, but that would not

17 stop the operation of the fire protection system?

18 MR. DUDLEY: That's correct. The staff

19 does not accept leakage inspection in and of itself as

20 an effective aging management program.

21 MEMBER FORD: Okay. So you're going to

22 rely on leakage then for localized corrosion events,

23 which this inspection analysis would not cover?

24 MR. DUDLEY: That's correct.

25 MR. HALE: But the fire protection program

1 would.

2 MR. DUDLEY: Okay, next item. The staff
3 questioned the management of wall thinning due to
4 small-bore pipes in the intake cooling water system.
5 This is an issue we touched on earlier. The
6 environment of the small-bore pipes is stagnant sea
7 water. The staff also questioned the possibility of
8 common node failure of the small-bore pipe during a
9 seismic event. In its response to the RAI and in
10 discussions with the staff, the applicant indicated
11 the following: that there are crawl-through
12 inspections of the majority of the ICW systems line
13 pipes, which include, and my guess is, I'm saying 80%
14 of the pipes in the system. The inspection also
15 included as much of each branch line as possible. The
16 branch lines consist of welded flanges to which small-
17 bore piping is attached. The flanges are the most
18 susceptible location for the development of corrosion
19 cells since there is a break in the epoxy lining where
20 you flange the pipe together.

21 The applicant has established a program to
22 replace small bore epoxy-lined carbon steel pipes with
23 a more corrosive-resistant material. To date, the
24 applicant has replaced approximately 75% of the carbon
25 steel pipes with the more resistant material.

1 As part of the nominal shift activities,
2 normal shift activities, operators walk down the ICW
3 system, note any leaks, and initiate corrective
4 action. The ICW system is an open system and is
5 designed to perform its intended function with a
6 sheered three-quarter inch instrument line and an
7 additional hundred-gallon-per-minute leak. These
8 maintenance history shows that the localized failure
9 of cement linings and internal epoxy coating of intake
10 cooling water lines result in small corrosion cells
11 that lead to two-wall leakage. The system and
12 structures monitoring program and the ICW inspection
13 programs are adequate to manage internal corrosion in
14 the ICW piping, and this item is resolved.
15 CHAIRMAN BONACA: I still have a question
16 about the 25% that has not been replaced. I mean,
17 you're telling me susceptible locations of the joints
18 between the small-bore piping and the larger-bore
19 piping. We have a lot of failures, evidently, and the
20 piping itself led to replacement with more corrosion-
21 resistant material. So I was saying that I understand
22 the reason, but are we saying that we're not going to
23 look at it and license renewal only looks at the
24 connections? I don't understand the logic.
25 MR. HALE: We credited two aging

1 management programs for aging of the small-bore lines.
2 One is internal inspections, our visual crawl-through
3 inspection; and the other being leakage inspection.
4 And the basis behind that is part of the corrective
5 action for the other lines be established an
6 acceptance criteria that says we can allow a certain
7 amount of leakage, so if we do get a leak, we'll go in
8 and repair. But it's not affecting the safety
9 function of the system.
10 CHAIRMAN BONACA: Could I ask you a
11 question? Since you replaced 75%, why didn't you
12 replace also the other 25%?
13 MR. HALE: Well, part of it is this system
14 is operating all the time, even during outage. It's
15 very hard to work in replacements of this type into a
16 normal, you know, you basically have to take these
17 systems out of service. So because our experience has
18 been small leaks, where the system safety function is
19 not affected, we essentially go into a corrective
20 maintenance mode for these small-bore lines.
21 CHAIRMAN BONACA: I guess I'm trying to
22 understand logic by which you're putting into aging
23 management for the extended period of time the
24 connecting parts, the joints, between the small-bore
25 and you're not putting this one. I mean, the same

1 thing you could do for those connections, right?

2 MR. MENOCAL: I think the only reason that

3 was put in there is to document the fact that when we

4 do the crawl-through, initially, it was thought well,

5 we don't look at the branch connections at all. But

6 we wanted to document and indicate in the response to

7 the questions that we received from the staff was the

8 fact that hey, when you do the crawl-through, you can

9 see so far down the line on the branch connections,

10 and we do, generally, are able to go and see up

11 through the first connection because, generally,

12 there's a flange there up the main process line. You

13 then connect the stainless steel piping, and what

14 we're going through now, our engineering standard now

15 for doing repairs or replacement here.

16 CHAIRMAN BONACA: What kind of leakage, I

17 mean, would you have to have in order to affect the

18 functionality of this system?

19 MR. HALE: 100 GPM, plus the sheered

20 three-quarter inch line.

21 CHAIRMAN BONACA: Plus the sheered three-

22 quarter inch line.

23 MR. HALE: And that evaluation and

24 assessment was put in place to specifically address

25 this issue.

1 CHAIRMAN BONACA: Okay. And your position
2 is that the localized damage, I mean, the effects are
3 cells, they're very small; therefore, they tend to be
4 a pinhole, even under the highest demand on the
5 system?
6 MR. HALE: Right.
7 MR. DUDLEY: And under seismic concerns,
8 also, a small pinhole leak would not necessarily
9 remove the functionality of the pressure boundary.
10 CHAIRMAN BONACA: Okay.
11 MEMBER ROSEN: Did I understand you to say
12 that the small-bore piping is Monel metal?
13 MR. MENOCAL: One of the replacement
14 materials that we're using is we're going to Monel.
15 MEMBER ROSEN: One of them and you're
16 going to, but you've already replaced 75%. What did
17 you replace it with?
18 MR. MENOCAL: Well, our standard right now
19 is replacement with Monel. The reason I'm hesitant to
20 say well, everything's been replaced with Monel
21 through the history of the plant is that we've have a
22 lot of materials we use. We use stainless, okay, for
23 some of the instruments, small lines; Monel; in the
24 past, there have been some aluminum bronze. So
25 there's other corrosion-resistant materials used, but

1 our standard today is to replace with Monel.

2 MR. HALE: If we have a leak, replace it

3 with Monel.

4 MR. DUDLEY: Stu Bailey was one of the

5 reviewers on this item. Stu, could you explain why

6 this acceptable to the staff?

7 MR. BAILEY: Hi, this is Stuart Bailey.

8 I'm not sure what you want me to add to that last

9 discussion. A lot of the questions that we had were

10 really to make sure that these pipes and lines would

11 maintain their integrity during a seismic event. A

12 lot of the questioning, there's been a lot of

13 discussion about these lines, and a lot of our

14 questioning and the reason for the open items was

15 really to make sure that we had a solid paper trail

16 covering what we're doing here.

17 The crawl-through on the large-bore piping

18 does allow them, by and large, to look at that first

19 flange. I don't know exactly what population that is

20 of the 25% that hasn't been replaced yet, but that's

21 s significant number of these epoxy-coated lines,

22 where the localized failure of the epoxy or that gap

23 right where the flange is has allowed these little

24 corrosion cells to go in. So the inspections that

25 they're doing really are indicative of overall what

1 they're seeing in the whole system and would be
2 leading.
3 And again, as they said, the corrosion
4 really has been in small cells that wouldn't affect
5 the overall integrity of the system during a seismic
6 event. As you said, it really runs all the other
7 safety-related systems, so it needs to remain intact
8 during those events.
9 So with the combination of the inspections
10 that they're doing on these lines, we feel that
11 they're adequately managing the aging for this system.
12 MEMBER ROSEN: What I'm trying to get is
13 a picture of where the system is today. What I
14 understand is that there were 75% of the original
15 epoxy-coated carbon steel has been replaced and that
16 it's been replaced with a mixture of Monel metal,
17 piping, aluminum bronze piping in some cases,
18 stainless steel piping; is that correct?
19 MR. MENOCAL: Yes. That's identified in
20 our application. In fact, when you look at the
21 application, you'll see all those materials.
22 MEMBER ROSEN: And you're aware of the
23 experience with aluminum bronze and other factors?
24 MR. MENOCAL: Like bleaching?
25 MEMBER ROSEN: Not necessarily with piping

1 but flanges. Not with forge material but cast
2 material.
3 MR. MENOCAL: I understand. Yes, a lot of
4 aluminum bronze has been replaced in the past.
5 MEMBER ROSEN: Oh, you replaced the epoxy-
6 lined carbon steel with aluminum bronze, and now
7 you're replacing the aluminum bronze?
8 MR. MENOCAL: Right. Believe it or not,
9 a lot of the, over the history of the materials of the
10 plant, aluminum bronze, at one time, was thought to be
11 a very excellent material in the industry for salt-
12 water systems, and it was one of the new magic
13 materials that a lot of the industry went to because
14 it was determined to be very excellent.
15 Then we found, based on our operating
16 experience, that we had the alloy of aluminum bronze
17 at St. Lucie. We didn't have that problem, and so
18 that material was replaced with stainless and another
19 material.
20 So yes, there's been a progression over
21 the 27 years of operation at the plant where we have
22 made changes in materials and determined the materials
23 not to be ideal.
24 MR. HALE: I think the point, I guess,
25 that we're trying to make with regards to the intake

1 cooling water system, we do crawl-through inspections,
2 which are quite extensive. They go through and they
3 crawl through the internals of the pipe. We looked at
4 the connections, had a lot of experience with this
5 system. If you pick a system on our site, which is
6 going to require more attention than any other system,
7 it's going to be this open salt-water system. We
8 probably spend more attention to this system than the
9 other systems from an aging management standpoint.
10 We've had a lot of operating experience
11 with regards to materials. I'd like to clarify there
12 were some aluminum bronze piping that was part of the
13 original plant design, and we've, through a learning
14 process, lessons learned, our corrective actions, feel
15 that we have an effective way for managing these
16 small-bore lines that consists of an internal visual
17 inspection at the connection because most of our
18 experience has been that's where the leakage has
19 occurred; and, secondly, through visual inspections,
20 we do not operate with leaks in the system. If the
21 leak is identified, a condition report is written, and
22 it's resolved. So those are the two aspects. It's a
23 two-headed program that evaluates that.
24 Now, in order to ensure that we can
25 adequately meet the safety requirements of the system,

1 we have a safety evaluation which demonstrates, even
2 with 100 GPM leak and another break in a three-quarter
3 inch connection, that the system can still meet its
4 safety requirements.
5 CHAIRMAN BONACA: The last question I had
6 for the gentleman here was, in order to feel confident
7 that a seismic event will not, in fact, cause gross
8 failure of the pipe means those were the experiences
9 that you have a corrosion cell, but you don't have
10 multiple corrosion cells in the same location or same
11 area coming up. Is this the case?
12 MEMBER ROSEN: Let me understand. What
13 size of the small-bore piping? Are we talking about
14 two inch and under or bigger than that?
15 MR. HALE: Yes.
16 MR. DUDLEY: It's four to six-inch pipe.
17 MEMBER ROSEN: So you have some four to
18 six-inch piping, which is aluminum bronze?
19 MR. MENOCAL: No, I don't believe we have
20 any four to six-inch piping which is aluminum bronze
21 in the intake cooling water system. It's hard for me
22 to speak specifically when you ask me line size of the
23 materials because we have an assortment.
24 MEMBER ROSEN: No, here's what I'm
25 concerned about. If you have four to six-inch piping

1 that's made of aluminum bronze, you're going to have
2 four to six-inch flanges of aluminum bronze. The
3 flanges are typically cast, that's where the alloying
4 will occur. And then you have to ask the question
5 about not leakage on normal operation but performance,
6 strength performance in seismic, in event of seismic
7 events. I mean, what are the required strengths of the
8 alloyed aluminum bronze flanges, and are they adequate
9 for 60 years regarding the design basis earthquakes.
10 MR. MENOCAL: I'm going to tell you, I
11 don't believe we have any aluminum bronze lines that
12 are in the four to six-inch range in the intake
13 cooling water system, and I say that because we have
14 experience with the aluminification of aluminum bronze
15 when we used to have loop water system at St. Lucie
16 for the intake cooling water pumps, which we
17 eliminated and went to --
18 MR. HALE: Again, the system, we say we're
19 going to have loss of material. Like Tony says, I
20 don't know that we have any four to six-inch aluminum
21 bronze. Again, the carbon steel pipe that's four to
22 six-inch is concrete lined. The only place where we
23 didn't have concrete lining and had to go to epoxy is
24 in the small-bore pipe.
25 As far as aluminum bronze, in original

1 plant design, we had some of the loop water system,
2 which was all small-bore, and we've removed all the
3 small-bore lube water piping and have gone to self-
4 lubricated pumps. So as far as de-alloyization, if we
5 had bronze, aluminum bronze, we assume loss of
6 material, okay? That could be from de-alloying, it
7 could be from any factor. If you look at our
8 evaluation, we say we have loss of material. How are
9 we managing loss of material? We're doing it via
10 internal inspections and leakage inspections.
11 MR. MENOCAL: I guess the key is it's not
12 bare piping. You're concerned with total loss of
13 mechanical properties of the piping because you have
14 de-alloying. The piping is coated; it has some kind
15 of internal coating, whether it's a concrete line or
16 epoxy. But you'll find that the failure mechanism is
17 localized failure of the internal --
18 MEMBER ROSEN: You're saying the aluminum
19 bronze is concrete lined?
20 MR. MENOCAL: No, I don't think we have
21 any aluminum bronze in the intake cooling system.
22 MR. HALE: What we can do is we can
23 provide you details of what pipe is aluminum bronze,
24 but my understanding, if you look at the application,
25 we don't have the facts right here, but aluminum

1 bronze is small-bore.

2 MEMBER ROSEN: Okay. That's what I need

3 to know.

4 MR. HALE: Right. Okay.

5 MEMBER ROSEN: What the extent of the

6 usage of that material and the largest sizes you've

7 used.

8 MR. HALE: And I think we clarify in the

9 application what's small-bore.

10 MR. MENOCAL: Yes, I don't recall the LRA

11 talking about any significant piping that would be

12 subjected to that. Do you have anymore questions on

13 this program?

14 MR. DUDLEY: No, I think we'll move ahead

15 to the next item.

16 MEMBER WALLIS: I think you better move

17 ahead. We're going to be here all day.

18 MR. DUDLEY: As a result of unexpected

19 aging degradation of alloy 600 materials and alloy 182

20 materials, the staff is developing guidance and

21 requirements for managing these aging effects. To

22 ensure applicants comply with future staff guidance,

23 the staff requested a commitment from the applicant.

24 The applicant committed to implement the commitments

25 made in response to NRC bulletins and any further NRC

1 communications associated with primary water stress,
2 corrosion, cracking, and nickel-based alloy
3 components. And on the basis of the commitment, this
4 item is resolved, and we've talked already about some
5 of the issues.
6 MEMBER WALLIS: It's a very strange thing.
7 A commitment, traveling with a commitment is like a
8 promise to implement a promise. Why do you need it?
9 You need another commitment? Maybe a commitment to
10 commit to commit . . .
11 MR. MEDOFF: Well, let me clarify this for
12 you, okay? The St. Lucie units are CE designed
13 plants. Unlike the Westinghouse designs, they have
14 additional Class I inconel nozzles to things like the
15 pressurizer and possibly the steam generator and the
16 hot legs. Unlike a lot of the Westinghouse
17 applicants, FP&L has opted to develop a low-volt alloy
18 600 program for all the alloy 600 components in the
19 reactor pressure boundary.
20 So we've had bulletins out on vessel head
21 degradation of the inconel nozzles to the upper vessel
22 head, but they also have plant-specific experience on
23 some of their other inconel nozzles to things maybe
24 like the pressurizer or the hot legs. And those
25 haven't been addressed by generic communications at

1 this point.

2 So you have to differentiate between

3 what's being handled for the head as required by the

4 new orders and how they're handling degradation in the

5 other nozzles at this point. And we had an open item

6 just to specifically clarify the differences, and,

7 basically, the applicant came back and indicated that,

8 currently, for the non-vessel head nozzles, they're

9 just currently using the ASME Section XI requirements

10 at this point.

11 But we did have a phone call with them,

12 and we did confirm that their commitment is really to

13 implement augmented requirements that we may develop

14 on inconel nozzles but, also, any recommended MRP

15 actions that would be found acceptable to the NRC. So

16 we feel that the commitment covers all the inconel

17 nozzles and not just the ones for the vessel head.

18 They are going to be required to follow the orders for

19 the vessel head nozzles.

20 MR. DUDLEY: I think, to answer your

21 question, there's a sensitivity among the reviewers

22 that, in the license renewal space, that there is

23 adequate regulatory commitments that inspectors and

24 regulators 20 or 30 years from now can go back and

25 regulate against, so this is really taking license

1 renewal commitments and ensuring that, even though
2 they're relying on the Part 50 operating plant
3 regulations, that, for renewal of the license, they
4 will highlight the fact that, in this area, for alloy
5 600, it will be managed by future positions by the
6 staff.
7 And in the next slide is exactly what Jim
8 described. This is another commitment that alloy 600
9 materials not connected with the reactor vessel head
10 will also be covered by the requirements of the alloy
11 600 programs in the future.
12 MEMBER FORD: Could you expand a little
13 bit on that, Noel? When you look at all the
14 degradation modes for alloy 600 and 690 and 182 and
15 83, there's a lot of degradation, so when you looked
16 at their alloy 600 program, did it take into account,
17 for instance, whether some of these had already been
18 repaired? And that gives rise to increased concern
19 about future failures. How deeply did you go into
20 their alloy 600 inspection program? There comes this
21 multitude of degradation modes and concerns about
22 prior -- do you understand what I mean?
23 MR. MENOCAL: Yes, and we had the same
24 issues, so let me explain how we handled it. At RC
25 bulletins 2101, 2201, and 2202 are specific to primary

1 water stress, corrosion, cracking that occurs in the
2 upper vessel head. It does not address industry
3 experience in other Class I inconel locations, okay?
4 So basically, we divided our open items into two, one
5 on the vessel heads and one on the remaining
6 components, okay? Basically, in the second open item,
7 we asked for clarification what additional inconel
8 components are covered by the scope of your program
9 and what are you doing to inspect them.
10 They gave us the locations, and they also
11 clarified that, currently, they're just using the
12 current Section XI programs. Now, depending on
13 whether it's, let's say, a nozzle joined by a partial
14 penetration weld as opposed to maybe an alloy 82, 182
15 safe nozzle weld, which is a full-penetration weld,
16 the ASME Section XI requirements are going to be
17 slightly different for the full penetration, but
18 they'll be maybe a surface exam, volumetric, or a
19 combination of the two. For the partial penetration
20 welds, the only thing that is required at this point
21 are leakage tests, VT2 examinations, visual
22 examinations.
23 One of the projects in our branch is to
24 look into whether the VT2's for the inconel locations
25 for partial-penetration welds are adequate at this

1 point; that's probably going to be a project down the
2 road. I think we're looking into it already, but, at
3 this point, we don't have any safety basis for
4 augmenting the requirements for the non-vessel head
5 locations.
6 Understand that, for their inconel
7 nozzles, to the pressurizer, and the hot legs, they do
8 have an alternative repair that they have a TLAA on,
9 and I'll get into that a little bit more, so that
10 everything is sort of tied together here, and they do
11 have a way of addressing it. But I think for the
12 inconel nozzles in the other locations, I think let's
13 reserve that for the TLAA, and that will maybe
14 clarify.
15 MEMBER FORD: So your answer is,
16 essentially, you're still relying just on the high
17 level non, really, operational specific.
18 MR. MEDOFF: What the process would
19 entail, though, if you were worried about, down the
20 road, what happens if we get degradation, if we get
21 severe degradation in a location, the process would be
22 we would look into it, we would issue generic
23 communications, and anything that would come out of
24 those communications would be addressed by the
25 applicants in their responses, and their commitment to

1 address those communications, we feel, takes care of
2 this.
3 MR. DUDLEY: Okay. I'll move on to the
4 next item. Staff requested the applicant to clarify
5 what aging management programs were used to manage the
6 aging effect of alloy 600 components not covered by
7 the bulletins. Okay. We're on slide 13? Okay.
8 The applicant plans to use risk inform
9 methodologies for the one-time small-bore Class I
10 piping inspection. The applicant confirmed that the
11 risk inform methodologies will not be used to
12 eliminate volumetric inspection of weld. In other
13 words, they can't use risk to say we don't need to
14 inspect them. The applicant committed to provide the
15 NRC an inspection plan, provide prior to the period of
16 extended operations, that describes the risk inform
17 methodology and addresses how the methodology will be
18 used to determine the location and the number of
19 small-bore piping components for inspection. This
20 commitment will be included as part of the FSAR
21 supplement.
22 CHAIRMAN BONACA: So they look at
23 susceptible locations irrespective of risk
24 significance to determine whether or not there is a
25 concern with corrosion of those pipings?

1 MR. DUDLEY: Yes.

2 CHAIRMAN BONACA: And that will be one-

3 time inspection?

4 MR. DUDLEY: Yes, and the details of the

5 program will be provided prior to the period of

6 extended operation. And this open item was a

7 commitment to include specific information in that

8 program description that the staff will need to

9 approve.

10 CHAIRMAN BONACA: Let me understand now.

11 So you do perform inspections in locations which are

12 not that significant; however, they are susceptible,

13 and you find that there is some --

14 MR. MEDOFF: Well, no, that's not quite

15 entirely true. This is an aging management program

16 for Class I locations, so they do provide a pressure

17 boundary function.

18 CHAIRMAN BONACA: Oh, yes. No, I'm

19 saying, but risk inform methodology will tend to focus

20 more on certain specific piece of pipings, and going

21 just for susceptible locations, you're looking

22 irrespective of which one is more significant or less

23 significant.

24 MR. MEDOFF: I think the approach that

25 they're taking for this is a combination of the

1 susceptibility in cracking or degradation and how, if
2 you had a failure of that location, how it would
3 contribute to the probable risk assessment.
4 CHAIRMAN BONACA: So if it is based on
5 susceptible, then you inspect, you find some locations
6 that tell you that there is some vulnerability, so you
7 have to establish additional inspections. The one-
8 time inspection, to me, means that. You don't expect
9 to find degradation, if you find it, you have to do
10 something more, you know, in the future.
11 So now, in the future, what would you
12 apply? Would you apply a risk inform methodology, or
13 would you just --
14 MR. MEDOFF: If I could clarify, the
15 history behind the Class I small-bore inspection
16 program is Section XI currently only requires visual
17 inspection of small-bore piping. The concern raised
18 by the staff is that there needs to be some volumetric
19 inspection of the small-bore piping, in addition to
20 Section XI.
21 Based on our aging assessment, we felt,
22 again, as we have communicated previously, for one-
23 time inspections, we don't anticipate finding anything
24 in this piping. So we've committed, as other
25 applicants have committed, to performing a one-time

1 volumetric inspection, in addition to the ongoing
2 visual inspections performed under Section XI.
3 So the volumetric inspection we're
4 performing, since it is small bore, and if you used
5 risk, you probably would eliminate all the small-bore.
6 There was some concern that, you know, we would
7 eliminate certain piping or eliminate the piping by
8 applying the risk inform methodology. Our intent here
9 was that, hey, the inspection technique is volumetric
10 because that is the concern the NRC has raised with
11 the small-bore piping. So what we're doing with risk
12 is we're using risk to establish the locations of the
13 ultrasonic inspections in the small-bore piping.
14 CHAIRMAN BONACA: So you're not looking --
15 okay, so you're not looking for the susceptible
16 locations to see if you have a problem, you're looking
17 only for the --
18 MR. HALE: Well, if I could clarify, as
19 part of your risk inform methodology, one of the
20 factors you consider is CUF and fatigue. So the risk
21 inform methodology will bring into play certain
22 factors where you would expect to see the cracking,
23 your more susceptible areas, as well as other factors.
24 But the concern that was raised is that we
25 were going to use risk inform to eliminate these

1 locations from doing volumetric inspection.

2 So in your answer to your question, one

3 time volumetric inspections but continuing ongoing

4 visual inspections, as we do today, for the small-bore

5 Class I piping.

6 CHAIRMAN BONACA: So what happens now when

7 you do the volumetric inspection, and now you find

8 that you have some pipes that have degraded, some of

9 them are not in risk of significant location, but they

10 are in susceptible location.

11 MR. HALE: We would have to, under this

12 program, it specifically indicates that, if we do find

13 degradation, we will have to take specific corrective

14 action, as we would in any case, to deal with that,

15 which may include replacement, it may include ongoing

16 inspections, whatever.

17 CHAIRMAN BONACA: It may include future

18 volumetric inspection.

19 MR. HALE: It may include that, you know,

20 depending on what we find.

21 CHAIRMAN BONACA: So what you're telling me, really,

22 the two programs are somewhat de-coupled, and this is

23 almost base lining your system prior to the entrance

24 into license renewal on the basis that looks not only

25 at risk significance but also susceptibility.

1 MR. HALE: Right, right.

2 CHAIRMAN BONACA: All right.

3 MR. HALE: And this has been an ongoing
4 item that was really raised, I think, originally and
5 right at the beginning with the first applicants that
6 came through, and this is, essentially, we're all
7 approaching it in trying to provide some confidence
8 that --

9 CHAIRMAN BONACA: Yes. Because some
10 applicants have come before you, and they stated that
11 there were, in fact, concern about symptom areas,
12 susceptibility, and that they identified degradation
13 in some small-bore piping. I don't remember which
14 applicant was that.

15 MR. MEDOFF: I don't think we've changed.
16 I think the approach taken by the staff --

17 CHAIRMAN BONACA: I understand that. I'm
18 only saying that your experience is that you don't
19 expect to see any degradation anywhere, but some
20 applicant came that said it wasn't there case. So
21 that's why I think --

22 MR. HALE: I believe A&O had some specific
23 failures, but they were thermally, there was some
24 thermal-fatigue issues with some small-bore
25 connections. I can't really --

1 CHAIRMAN BONACA: Arkansas One, yes.

2 MR. HALE: And we have not seen that.

3 CHAIRMAN BONACA: Okay.

4 MR. HALE: In fact, you know, there were
5 other factors involved besides just, you know, small-
6 bore issues. There were some fatigue problems, as
7 well.

8 CHAIRMAN BONACA: Okay, thank you.

9 MEMBER LEITCH: There has been recent
10 industry experience with one older plant that had
11 scheduled 40 screwed connections in small-bore Class
12 I piping that yielded some leaks due to, I guess, lack
13 of specificity as far as thread engagement and details
14 of how the system was assembled.

15 MR. MEDOFF: In a threaded connection?

16 MEMBER LEITCH: In a threaded connection,
17 yes. I think, in more recent plants, this piping is
18 all welded construction. Is that the case at St.
19 Lucie?

20 MR. MEDOFF: Let me clarify something.
21 This inspection is specific to small-bore Class I
22 locations that are joined by full-penetration butt
23 welds.

24 MEMBER LEITCH: Okay.

25 MR. MEDOFF: Okay.

1 MEMBER LEITCH: But then my question is is
2 there screwed piping in that service at St. Lucie,
3 particularly St. Lucie 1, I guess.
4 MR. HALE: St. Lucie 1 is built B31.7, so,
5 as I understand it, I'm not a code expert, but I don't
6 believe screwed connections would be allowed for Class
7 I connections in the ASME code.
8 MR. MEDOFF: That's a pretty stringent
9 nuclear specification.
10 MR. HALE: For piping covered by the code.
11 You know, you might have some instrument, but that's
12 outside of the Class I.
13 MR. DUDLEY: Next item has to do with
14 reactor vessel surveillance capsules. The staff
15 questioned why the reactor vessel surveillance capsule
16 removal and evaluation subprogram removed the last
17 capsule before reaching the peak end-of-life fluents,
18 as indicated in tables 4.2-3 and 4.2-4 in the
19 application.
20 The applicant explained that the end-of-
21 life fluents in tables are based on 60 effective full-
22 power years. However, the capsule removals in Unit 1
23 is based on a 52 effective full-power-year fluents,
24 and the capsule removal for Unit 2 is based on a 55
25 effective full-power-year fluents. And on the basis

1 of the 52 and 55 effective full-year fluents values,
2 the capsule removal schedules are acceptable. This
3 was a misunderstanding of the information that was
4 provided in the table at the end of the chapter or
5 section concerning reactor vessel embrittlement.
6 CHAIRMAN BONACA: The projected effective
7 full-power years for 60 years of operation is what?
8 48?
9 MR. DUDLEY: Forty-eight is normally what
10 you see.
11 CHAIRMAN BONACA: This exceeds it.
12 MR. DUDLEY: This exceeds it, so there's
13 no problem there.
14 The next issue, the staff questioned the
15 applicants basis for not managing stress relaxation
16 for non-Class I bolting material. Non-Class I bolting
17 does experience stress relaxation at temperatures
18 above 700 degrees Fahrenheit. The non-Class I bolts
19 at St. Lucie are environments that have temperatures
20 below the 700 degrees Fahrenheit, and, therefore, do
21 not require an aging management program specific to
22 stress relaxation.
23 MEMBER FORD: The use of a specific
24 number, you come across it in the PTS area and other
25 areas, how much below 700?

1 MR. DUDLEY: I think two or three-hundred
2 degrees.
3 MR. MEDOFF: Let me clarify how I handled
4 this open item. When I was performing my review, I
5 noticed that the identification of, basically, the
6 applicant has one global aging effect, which is loss
7 of closure integrity, and they evaluate it for
8 different mechanisms, such as severe corrosion or
9 cracking or stress relaxation. And I noticed that, in
10 their identification of this aging effect for the non-
11 Class I was handled a little bit different. They
12 didn't identify stress relaxation as a mechanism
13 leading to the loss of closure integrity. So we asked
14 a question in the open item why, provided
15 justification.
16 The response we got back from the
17 applicant was, basically, they use different materials
18 for the Class I in contrast to that used for the non-
19 Class I RCS bolting. And they gave us the threshold
20 for stress relaxation was for those materials.
21 To confirm the validity of the responses,
22 I went to the appropriate ASME section and looked at
23 the footnotes they had stress relaxation. It did
24 confirm that ASME has those thresholds for stress
25 relaxation in different materials.

1 So based on the use of 700 degrees as the
2 threshold for stress relaxation and Essay 193, Grade
3 B-7 bolting, which is being used for the non-Class I
4 RCS bolting, that stress relaxation would not be an
5 applicable effect for those bolting materials because
6 the operation of the RCS would be at a temperature
7 lower than that. Probably around 560 to 600, so maybe
8 100 to 140.
9 MEMBER WALLIS: Not where the bolts are.
10 The bolts are actually cooler than that.
11 MR. MEDOFF: Right.
12 MR. DUDLEY: Next slide. The staff
13 questioned the applicant's basis for not managing
14 possible crack propagation from alloy 182 welds in the
15 base metal of the pressurizer nozzles and thermal
16 sleeves. We had touched on this earlier. The thermal
17 sleeves are not welded and do not perform a pressure
18 boundary function. The thermal sleeves are machined,
19 inserted, and expanded. Therefore, since there are no
20 welds, there is no possibility of crack propagation to
21 the base material that forms the pressure boundary,
22 and this item is resolved.
23 And I'll move onto the next item. The
24 Interim Staff Guidance, the staff stated that the fuse
25 holders are considered passive electrical components

1 and should be brought into scope of license renewal
2 and subject to an aging management review. The
3 applicant identified electrical boxes that contain
4 fuses that were brought within scope. The fuse
5 holders are located in electrical boxes in the
6 electrical equipment rooms in the Unit 1 and Unit 2
7 reactor auxiliary buildings. The applicant conducted
8 an aging management review of the effects of aging
9 stressers, such as vibration, thermal cycling,
10 electrical transients, mechanical stress, fatigue,
11 corrosion, chemical contamination, and oxidation of
12 connecting surfaces. The applicant concluded that no
13 aging management programs are required.
14 The staff did extensive review of this
15 since this is the first application that addresses the
16 Interim Staff Guidance on this issue, and some of the
17 things that the staff took into consideration when
18 they reached the acceptance of the applicant's
19 position was that the fuse holders are installed in
20 parallel with breakers to address regulatory guide
21 associated with providing double isolation for non-
22 safety-related loads powered from safety-related power
23 supplies.
24 The non-safety-related loads include
25 instrumentation and heater strips to electrical

1 panels. The fuse holder clips are made of copper or
2 a copper alloy plated with a corrosion-resistant
3 material, either tin or silver, and the fuse holders
4 are in a mild, non-air-conditioned environment, and
5 the staff was unable to identify any aging effects
6 that would degrade the performance of the fuse holder.
7 And, on this basis, this item was resolved.
8 Finally, the last open item, the St. Lucie
9 Units 1 and 2 have experienced instances of alloy 600
10 instrument nozzle leakage. Four Unit 2 pressurizers
11 steam space instrument nozzles and one Unit 1 reactor
12 coolant system hot leg instrument nozzle were repaired
13 with a half-nozzle repair technology. A mechanic
14 analysis was submitted to support the St. Lucie Unit
15 2 pressurizer steam space half-nozzle repair performed
16 in 1994. The staff is currently reviewing several
17 aspects of the half-nozzle repair and associated
18 topical reports. The staff is evaluating the
19 acceptability of leaving the half-nozzle repairs in
20 place due to the unknown effects of primary coolant
21 contacting the ferritic material of the nozzles, and
22 this is a spin-off of the Davis Besse concerns.
23 The staff is reviewing a relief request
24 for leaving the half-nozzle repair in place for one
25 cycle. Combustion engineering identified calculational

1 errors in its topical report associated with the
2 fracture mechanical analysis supporting half-nozzle
3 repairs, and the staff is reviewing that topical
4 report.
5 The applicant also submitted a site-
6 specific Class II proprietary calculation for
7 evaluating the crack growth associated with small-
8 diameter nozzles for St. Lucie Units 1 and 2, and
9 that's also under review by the staff.
10 Since the technical issues associated with
11 the half-nozzle repairs have not been resolved for the
12 current period of operations, the applicant cannot
13 demonstrate that the fatigue analysis can be re-
14 evaluated for the period of extended operations.
15 We're in a position where we, as a staff, do not know
16 what's appropriate for a 40-year time period.
17 Therefore, it's impossible to extend that calculation
18 to the 60-year time period.
19 However, the applicant committed to
20 implement any further NRC requirements associated with
21 half-nozzle repairs, and, on the basis of this
22 commitment, this issue is resolved, and it's resolved
23 in license renewal space and, again, we rely on the
24 Part 50 operating license base for resolving the
25 adequacy of the half-nozzle repairs.

1 What's expected to happen is that
2 accepting their commitment, in license renewal space,
3 we can issue the license. As soon as the license is
4 issued, when they come in with another relief request,
5 they'll have to evaluate for the 60-year life of the
6 plan, and the staff will have the opportunity to
7 review that analysis.
8 MEMBER LEITCH: I don't understand what a
9 half-nozzle repair is. Could someone educate me,
10 please?
11 MR. MEDOFF: Let me clarify the whole
12 thing.
13 MR. HALE: We brought a drawing.
14 MR. MEDOFF: He has a drawing, but,
15 basically, like, the vessel head nozzles, the inconel
16 nozzles to the pressurizer, the hot leg, possibly the
17 steam generator are welded to the ferritic shells or
18 piping using partial penetration welds fabricated from
19 alloy 182 or 82.
20 Basically, if you look at the drawing,
21 basically, what they do is because of concerns, they
22 do not propose to take out the leaking weld when they
23 have to repair a leaking nozzle. Instead, what
24 they're doing at St. Lucie is cutting the nozzle,
25 basically, in half and installing a new alloy 600

1 nozzle partially through the thickness of the shell or
2 the vessel.
3 MEMBER WALLIS: When you say "cutting in
4 half," in which direction are they --
5 MR. MEDOFF: They have a process to go
6 inside the nozzle and cut the original design, and
7 then they removed the top portion of the alloy 600
8 nozzle, and they stick in an alloy 600 nozzle
9 partially through, and then they weld it from the top
10 of the -
11 MEMBER WALLIS: So the cup is across not
12 lengthwise?
13 MR. MEDOFF: No, it's across. It's across
14 the nozzle. So they cut it across, then they stick in
15 a new alloy 600 nozzle.
16 MEMBER LEITCH: And that provides a
17 leakage path directly --
18 MR. MEDOFF: Well, they weld it from the
19 top of the vessel. Let me go through it. When they
20 stick in the alloy 690 nozzle that they're replacing
21 the original nozzle design with, it leaves, there are
22 two things that happen. It leaves the original flaw
23 in the original weld material intact without repair,
24 and it also exposes the ferritic shell or piping
25 component to the borated coolant.

1 Basically, CE has two designs. One is
2 called a mechanical nozzle seal assembly, which I'm
3 not going to get into right now because they don't use
4 it. But the other is half-nozzle design. There were
5 three time-limiting mechanisms that had to be
6 addressed if they wanted to use this half-nozzle
7 design. One is since you're leaving the flaw intact
8 in the original weld material, you had to address
9 fatigue crack growth into the ferritic material.
10 The second time-limiting aging effect you
11 had to address was, since you're exposing the
12 original, the ferritic material to the boric acid in
13 the coolant, you had to address severe corrosive
14 attack of the ferritic material by the borated
15 coolant.
16 And then the third thing, which we
17 concluded wasn't an issue, was possible growth by
18 stress corrosion because, really, you're talking about
19 stress corrosion into a ferritic material, which we
20 haven't concluded is an issue at this point.
21 So the only thing we've made them do, and
22 the applicant did the appropriate thing, is they
23 identified that we had to address the fatigue crack
24 growth and the ferritic corrosion assessment as time-
25 limiting aging analyses and submitted as part of a TL

1 life for the half-nozzle designs.

2 There was some debate with the industry

3 whether they needed relief requests submitted under 10

4 CFR 50.55 (a) associated with these replacement

5 designs, and we found the clause in Section XI that

6 requires relief.

7 So under the current operating term, they

8 have submitted a relief request that is now under

9 review by the staff. Included as part of the relief

10 request is the appropriate fatigue and ferritic

11 corrosion assessments for 40 years.

12 Now, we have some issues that we think CE

13 and the applicant needs to address, but we need more

14 time to look into them, so the process that we're

15 using right now is to issue the relief for one cycle,

16 and the SC should be coming out within the next month

17 or so. And then, to issue the renewed license, and

18 when they have to come back in for relief for the

19 extended period of operation, they'll have to have an

20 appropriate relief, and then the TLAA's will cover 60

21 years in that case.

22 So I think, by taking this process, it

23 will give us time to address possible implications of

24 the Davis Besse data on the ferritic corrosion

25 assessment and to take another look at the fatigue

1 assessment. And I think that's a reasonable approach
2 because it doesn't hold up their license, but they
3 will still be required to do what they will be
4 required to do under the current licensing space.
5 MR. DUDLEY: Okay. The last slide before
6 lunch, I just want to put this slide up and indicate
7 that there were also confirmatory items, and the
8 confirmatory items were simply to indicate that there
9 would be revisions to requests for additional
10 information responses and several FSAR supplements, as
11 shown on this slide. I don't think I need to go into
12 anymore details but --
13 MR. KUO: Noel, are you going to go into
14 the ROP process status?
15 MR. DUDLEY: Yes, I'm sorry, yes. That's
16 the end of the confirmatory items, open items, and I
17 can go into ROP areas, and I should be able to get to
18 this in about five minutes.
19 MEMBER LEITCH: Just one question before
20 you move into that, Noel. Would you expect that there
21 would be any license conditions? Or do you not make
22 that decision until you're further down in the
23 process?
24 MR. DUDLEY: At this point, the only
25 additional license condition is that they incorporate

1 the commitments that are identified in the FSAR
2 supplements and the updated final safety report at the
3 next update.
4 MEMBER LEITCH: And that's almost a
5 standard, if you will, license condition. Everybody
6 gets that one, I guess.
7 MR. DUDLEY: Right. So that's why we're
8 concerned about tracking the commitments that have
9 been made during license review process, so that that
10 will become part of the UFSAR and will provide a
11 regulatory basis for inspecting and regulating against
12 the commitments that were made in the license renewal
13 review process.
14 MR. HALE: And if I could, Noel, what we
15 did with Turkey Point is there is a specific condition
16 of license that's identified which references the SAR
17 supplement and indicates these commitments have to be
18 complete or consistent with the schedule in the SAR
19 supplement. So while they don't identify each one of
20 those commitments as a condition to license, there is
21 a statement in the license which will refer to the
22 commitments made for license renewal.
23 MEMBER LEITCH: Okay. That's the only
24 condition you expect then, at this point?
25 MR. DUDLEY: That's correct. We're trying

1 to identify the commitments that were made and put
2 them into a Part 50 operating licensing space, so they
3 can be tracked as part of the operating license
4 activities.
5 MR. HALE: With regards to this half-
6 nozzle item, I just want to be, the crux of the issue
7 is really corrosion rate or that piece of carbon steel
8 there. We relied on CE data, and there is some
9 difference of opinion between the industry and the
10 staff, and, with good reason, considering Davis Besse,
11 but our position and the information we provided is to
12 show that this is not an active leak. It's not like
13 the head penetration, but, certainly, we understand
14 the concern the staff has. Our position is that we've
15 done an adequate assessment on the fatigue and the
16 corrosion rate based on available data we had at hand.
17 The issue that we have right now is what
18 is the right corrosion rate, based on what we're
19 learning from Davis Besse. And I think once we do
20 that, we'll be able to address the balance of this
21 issue.
22 The fatigue, though, I think, although the
23 staff has not completed their review, the fatigue
24 analysis, we did submit a plant-specific fatigue
25 analysis for St. Lucie.

1 MEMBER WALLIS: Is there any comparison to
2 Davis Besse at all? I mean, this isn't concentrated
3 boric acid which has been concentrated by flashing and
4 all that stuff. It could be a different temperature.
5 MR. HALE: It really comes down to
6 evaluating the corrosion rate under three different
7 conditions: one, at 100% power, where you have a very
8 low corrosion rate; at heat-up and cool-down, where
9 you might have slightly higher; and then, possibly,
10 some of these may see just air during shut-down
11 conditions. So it's kind of a complicated assessment
12 to perform to establish what is the aging and whether
13 it is going to. But our feeling is, because it's not
14 an active leak, it's not the same situation. We
15 documented that in some of our RAI responses. But
16 again, that's the crux of the issue is how you
17 establish that corrosion rate and what's the right
18 thing to do, and the industry and the staff have to
19 come to agreement in what is the right assumption
20 there.
21 MEMBER FORD: But as I understand it, from
22 the license renewal aspect, what you're essentially
23 saying is, hey, this is such a physical unknown in
24 terms of corrosion rates or propagation rights,
25 whether it be fatigue or whether it be stress

1 corrosion cracking. But we are going to give you a
2 license renewal, but, hey, from now on, you've got to
3 conform to the way industry is, MRP, or whoever else
4 is coming up with these predictions.
5 MR. DUDLEY: Yes, that's correct. And
6 it's not going to be, I don't believe this is going to
7 be unusual since there is a continued operating
8 experience where we find unexpected corrosion and
9 aging degradation for component and how do you deal
10 with that in the license renewal space during the time
11 that it's been identified and the years that it may
12 take to come to resolution on what's an appropriate
13 aging management program.
14 MEMBER FORD: Just for interest, are there
15 other stations with this same half-nozzle thing?
16 MR. MEDOFF: Yes, Arkansas Nuclear One.
17 I mean, Arkansas Nuclear One Unit 2.
18 MEMBER FORD: Has it also got this?
19 MR. MEDOFF: Yes.
20 MR. HALE: Dr. Ford, if I may, what
21 happened is CE submitted a topical to cover this
22 repair methodology the utilities could reference and
23 utilize. In fact, there was actually an SE issued on
24 the topical. There were issues raised by the staff on
25 the adequacy of the fatigue analysis. And in addition

1 to that, the Davis Besse issued occurred. What has
2 happened is CE has submitted a revised topical to
3 address those issues, and that is yet to be approved
4 yet.
5 And so the ultimate goal would be come to
6 agreement between the staff and CE and what are the
7 appropriate assumptions in the way you analyze and
8 deal with this modification. And once that's issued,
9 then the rest of the plants will be able to utilize
10 that topical as their basis. Because it's up in the
11 air right now and where we are in the St. Lucie
12 review, I think this is the appropriate way to deal
13 with it until such time as that topical is approved
14 for us.
15 So that's one of the reasons. I agree
16 with you that this needs to be addressed as a standard
17 repair for the CE plants, and, hopefully, we'll get to
18 that point here.
19 MR. MEDOFF: And actually, I think the
20 approach we're taking does give us time to address it.
21 We don't take degradation of inconel components
22 lightly, and I think the approach we're taking is to
23 give us time to look at this so we don't rush into an
24 improper conclusion. I'm in constant discussion with
25 my sec chief, Stephanie Coffin, and with my branch

1 chief, Bill Bateman, about this. We do not want to
2 have another Davis Besse event. We are going to get
3 severely criticized if that happens again.
4 So I think, right now, by deferring this
5 to the next relief request and to give us time to look
6 into the Davis Besse data on the corrosion assessment
7 and even a chance to re-look at the fatigue
8 assessment, it will give us time to address the TLAA's
9 for the half-nozzle design.
10 MR. DUDLEY: This is for the revised
11 oversight process. The performance indicators for St.
12 Lucie were last updated in December 2002. All the
13 indicators are green. However, I went back to look at
14 some of the experiences. They've had two trips in the
15 last year. In October of 2000, there was a manual re-
16 trip. Based on the loss of condenser vacuum, they
17 were re-aligning the condenser vacuum system, and, due
18 to the misalignment, they lost pressure. They took
19 the plant off the line.
20 In April of this year, there was a reactor
21 trip. It must have been occurring during start-up
22 because an auxiliary feed pump tripped, was started
23 and then tripped offline, and I suspect that they lost
24 steam generator water level and tripped offline.
25 Neither of these events were recognized as a

1 regulatory problem, and there was no non-cited
2 violations issued in response to the trips in either
3 case.
4 There were several events of not following
5 your radiological control programs. There was one
6 instance of radioactive material, small radioactive
7 spec being carried off-site. There was a long story
8 with that. People were sent in to high radiation
9 areas without the appropriate radiological
10 evaluations. And that was the only area that I could
11 find where there appeared to be several events or
12 missteps by the applicant.
13 I did come across a finding that, based on
14 results of inspection, this was done by the QA
15 department of Florida Power and Light for St. Lucie.
16 Based on the results of the inspection, no findings of
17 significance were identified. The implementation of
18 the corrective action program was acceptable. There
19 was an isolated maintenance effectiveness issue
20 involving repair of a failed emergency diesel
21 generator cooling system radiator. Overall, the
22 licensee properly classified discrepant conditions and
23 corrective actions were completed in a timely manner
24 with respect to plant risk.
25 The licensees quality audits were

1 effective in identifying deficiencies in the license
2 programs, and the inspectors did not observe a
3 reluctance to report safety concerns. And this was
4 taken out of inspection report 2002005 for St. Lucie.
5 MEMBER WALLIS: So those are comments, in
6 general, about the corrective action program across
7 the board?
8 MR. DUDLEY: That's correct, and that was
9 made by NRC inspectors.
10 MEMBER ROSEN: That is very helpful. I
11 appreciate your looking at the operating experience
12 and telling us about the results of the realized
13 oversight process at the applicant's facility.
14 MEMBER LEITCH: Did I understand you to
15 say that this was a hot particle that was transmitted
16 off-site, or was it --
17 MR. DUDLEY: They were in the process of
18 decontaminating materials, and several people, when
19 they came out of the radiological controlled area, and
20 Steve may help me out here with details, but they were
21 identified as they were unable to pass through the
22 last rad monitor when exiting the plant. They went
23 through extensive decontamination. One individual,
24 they decontaminated him three or four times, and each
25 time they completed decontamination, they determined

1 that there was still radioactive material somewhere.
2 They assumed that it was an internal take-up.
3 It turned out that he had a flea on his
4 underwear. They allowed him the modesty to wear his
5 underwear when they were doing the decontamination,
6 but when he went into the shower, he took off his
7 underpants, took a shower, came back, and put them on.
8 So that's about as far as I can go. Steve, do you
9 have anything --
10 MR. HALE: As part of the procedures, they
11 are required to do these, you know, and they
12 inappropriately determined that it was internal. But
13 when you do that, when the person comes back into the
14 site, the first thing he has to do is he's got to be
15 monitored. And what happened is, when he came back
16 into the site the next day, he had no internal
17 radiation. So they immediately reacted to that, went
18 to his hotel room with monitoring equipment, and was
19 able to find the flea, as Noel said.
20 MEMBER WALLIS: So a radioactive flea?
21 There's radioactive fleas?
22 MR. DUDLEY: That's nomenclature for a
23 very small radioactive particle.
24 MEMBER WALLIS: Oh, oh.
25 MR. HALE: But the corrective action has

1 been, there was a number of corrective actions that
2 fell out of this, but one of the corrective actions is
3 that they have to remove all clothing and put on a
4 modesty garment to do the whole body counting and
5 everything when somebody can't get through the portal
6 monitor when they're leaving the site.
7 MEMBER LEITCH: Do you have a chronic or
8 an ongoing problem with fuel fleas at St. Lucie?
9 MR. HALE: I don't believe so. This
10 happened to be a specific case. In fact, it was
11 related to decon up ahead for the full head
12 inspection. And, as you might imagine, it was an
13 abnormal situation in terms of radiation controls and
14 that sort of thing. But it's gotten a lot of
15 scrutiny. In fact, correct me if I'm wrong, Caudle,
16 wasn't there a regional inspection group came in to
17 look at some events that occurred during that. But
18 the way Noel described, it was the event of the hot
19 particle.
20 MEMBER LEITCH: Okay, thanks.
21 CHAIRMAN BONACA: Your presentation is
22 completed?
23 MR. DUDLEY: I'm completed with this
24 portion of the presentation.
25 CHAIRMAN BONACA: It is a good time to

1 take a break for lunch.

2 MEMBER ROSEN: Mario, are we going to go

3 over what open items we have and where we've asked the

4 material and haven't got the answer at some point at

5 the end of the day, or should we do it now?

6 CHAIRMAN BONACA: I'm sorry, which issue?

7 MEMBER ROSEN: Well, there's just one open

8 item that I have left.

9 CHAIRMAN BONACA: Okay. If you want to

10 close it now. We are running --

11 MR. DUDLEY: If you'll let us know, we can

12 get the answer for after lunch.

13 MEMBER ROSEN: Okay.

14 MR. DUDLEY: Which issue is that?

15 MEMBER ROSEN: The aluminum bronze, the

16 extent of the alloying and the use of aluminum bronze

17 in the ICW system and the adequacy of aluminum bronze

18 for the extended license term.

19 MR. MEDOFF: In other words, you don't

20 want it looking like it's de-alloy?

21 MEMBER ROSEN: Let me just say I have a

22 lot of experience with aluminum bronze de-alloy, and

23 I don't want to repeat it.

24 CHAIRMAN BONACA: Okay. We are running

25 about 40 minutes late, so I hope, in the afternoon, we

1 can recoup some of the time.

2 MR. DUDLEY: I think we can make some

3 progress there because, this afternoon, it was more a

4 broad overview of the process.

5 CHAIRMAN BONACA: Okay, good. With that,

6 I think we need to have lunch, so we're going to take

7 a break for an hour and get back at 10 after one.

8 (Whereupon, the foregoing

9 matter went off the record at

10 12:12 p.m. and went back on the

11 record at 1:10 p.m.)

12 CHAIRMAN BONACA: Mr. Dudley, please

13 resume the presentation. Realize, again, that we are

14 40 minutes late. Therefore, it would be good to catch

15 up. I see, in the presentations, some of them are of

16 a process nature, and you may make a judgment on what

17 you want to skip.

18 MR. DUDLEY: We have some preliminary

19 information on the requests from Mr. Rosen, but I'd

20 like to wait until the end of the presentation to see

21 if we get more clarification on the size of the pipes.

22 CHAIRMAN BONACA: Okay.

23 MR. DUDLEY: So I'll jump right into where

24 we left off. This afternoon, Greg Galletti will

25 describe the staff's review of the scoping and

1 screening methodology, and I will summarize the
2 results of the scoping and screening review and the
3 aging management review process. And at this point,
4 I'll turn it over to Mr. Galletti, who also led the
5 scoping and screening review audit.
6 MR. GALLETTI: Good afternoon, Chairman
7 Bonaca and committee members. My name is Greg
8 Galletti. I'm an operations engineer in the Equipment
9 and Human Performance Branch in NRR. We have
10 responsibility for reviewing the scoping and screening
11 methodology and performing the audit as part of that
12 review process.
13 What I'd like to do is briefly go over the
14 audit process with you. Again, much of this will be
15 repetitive from what you've heard in the past. And
16 then what I'd like to do is go into, essentially, the
17 big open item that we had, which was the A2 issue,
18 seismic II over I.
19 And then, if you'd like, I can spend a
20 minute or two going over some insights that we gained
21 from looking at a review performed by a licensee that
22 had the previous benefit of performing a license
23 renewal application in the past, that is Turkey Point.
24 And there's some benefits that we saw in the
25 experience that they gained through that Turkey Point

1 audit experience that we'd like to share.

2 With that, let me just get into the

3 basics. The team that I have is, essentially, three

4 members that go out on the audit, and they are members

5 of the Equipment and Human Performance Branch. And in

6 preparation to do that audit, we go out on what we

7 call a procedures documentation review trip, which we

8 go to the licensee, we gather information pertaining

9 to the license renewal application. That is, we go

10 and we get things such as design basis documentation,

11 scoping and screening result reports, any design basis

12 information that may help us review the application

13 and review the process that they went through to

14 determine what systems are in scope and, ultimately,

15 what structures and components are then subject to

16 aging management review.

17 We go and we get that information and then

18 spend several weeks back in the office doing what we

19 call conservative desktop review. And again, we'll go

20 through the FSAR, we'll go through the application,

21 we'll look at how the application is structured in

22 reference to the requirements of the rule to ensure

23 that they cover the safety-related aspects, the SSC's

24 that are safety related, the SSC's that we would

25 consider non-safety related, and that they have done

1 an analysis to consider what SSC would be brought into
2 scope as a result of what we characterize as their
3 regulated events.
4 Once we get through that process in-house,
5 we then go back out to the licensee and spend a full
6 week as a team, three members and the project manager.
7 And during that week, we, again, go through, in
8 detail, the implemented guidelines. In this case, the
9 licensee put together a suite of procedures called
10 engineering instructions, and that suite of procedures
11 was written and implemented in accordance with their
12 10 CFR, Appendix B, safe quality assurance program,
13 which I think you heard earlier today.
14 As part of the review, we will go through
15 each of those procedures in detail with the cognizant
16 engineers responsible for that particular discipline.
17 So, for instance, there will be a scoping and
18 structural, mechanical and structural scoping
19 evaluation done, and we would bring in those engineers
20 responsible for that activity at the utility to
21 discuss both the practice, that is the engineer
22 instruction, how well that was understood, how well
23 that was written to reflect the process that the
24 licensee wanted them to perform. And then we'll
25 actually go in and select certain systems to review.

1 In this case, as we've done in the past,
2 we tried to do what we consider a smart sample. We
3 look at four mechanical systems right off the bat:
4 component cooling water, safety injection, auxiliary
5 feed water, main feed water, and then main steam and
6 condensate.
7 And there's several reasons why we use
8 this particular group of systems. One is, as you can
9 tell, there's a combination of both safety and non-
10 safety related systems, so we want to get a sense for
11 how they are reviewing and analyzing that information,
12 the design-basis information related to those systems.
13 Secondly, they have pretty robust systems. They're
14 pretty complicated. They've got lots of components.
15 So it gives us a good opportunity to really exercise
16 the process. There's a lot of information, a lot of
17 material, a lot of keen ideas to actually go and
18 review. Thirdly, there's a lot of interface between
19 some of these systems. Some of the systems, the
20 component cooling water would have both non-safety and
21 safety-related components, and between the systems,
22 there would be interfaces. And, as you know, in the
23 past, sometimes these interfaces have been of much
24 interest of the staff in terms of how the licensee has
25 established boundaries, how they've accommodated

1 equipment at those boundary locations in terms of
2 their process.
3 Once we go through that process, we'll
4 look in detail at those systems. In this case, we did
5 just that, and we found, quite frankly, that both
6 their implementation guidance was very well
7 constructed, detailed, robust, and provided the
8 guidance that we felt was necessary for their staff to
9 implement their process. And two, we looked at the
10 scoping and screening results reports for these
11 systems, as well as some structures, specifically the
12 auxiliary building, I think we looked at the turban
13 building; there were several other structures that we
14 looked at to try to glean a better understanding of
15 how they implemented the process.
16 Overall, our findings were that, as I
17 mentioned, their implementing guidance was very well
18 detailed. Their implementation of that guidance and
19 their result in the reports were very well detailed.
20 We didn't find any major deviations in what they
21 provided in terms of the scoping. Their technical
22 basis documentation, the DBD's, the FSAR, all of that
23 sort of information, their hazards analyses to support
24 some of the regulated event reviews were very explicit
25 and provided a very good source for identifying

1 intended functions for those systems and,
2 subsequently, the intended functions for the
3 components within those systems that were part of the
4 review.
5 MEMBER LEITCH: Is three days typical for
6 the on-site portion of this inspection?
7 MR. GALLETTI: Generally, it's about four
8 days. The reason we had limited it to three days in
9 this case is much of the review, the process had been
10 the same as for Turkey Point. So we were coming into
11 this with quite a bit of prior knowledge. Normally,
12 what we would do is come in on a Tuesday and, you
13 know, spend the full week.
14 As a result, our findings were, basically,
15 that we felt their process was certainly consistent
16 with the regulations they had implemented in
17 accordance with their administrative controls. Again,
18 because they done their review under their Appendix B
19 quality assurance program, we had the added benefit of
20 looking at some of their internal QA audits of their
21 own process. And from that, we gleaned some insights
22 as to how they had performed their activities.
23 MEMBER ROSEN: Is that unusual the
24 applicants would do these reviews under procedures
25 that are covered by Appendix B? I should think

1 everybody would do that.

2 MR. GALLETTI: No, it's not unusual to do

3 it that way but it, quite frankly, some have not

4 chosen to do it under their Appendix B program.

5 MEMBER ROSEN: I don't understand how they

6 could. I mean, if you read Criterion Three, Appendix

7 B, Criterion Three would say that safety-related

8 activities should be conducted in accordance with

9 approved procedures and instructions.

10 MR. GALLETTI: Right. Now, these are

11 approved procedures and instructions at all the sites,

12 but it's just the level of, I'd say, scrutiny or,

13 perhaps, pedigree of those procedures where we've seen

14 that some have done it strictly under their Appendix

15 B program. Others have not, although they have quite,

16 you know, approved procedures. They've gone through,

17 like, types of reviews. They've been reviewed, but

18 they don't --

19 MEMBER ROSEN: I'm not concerned with St.

20 Lucie. I think St. Lucie has done the right thing.

21 MR. GALLETTI: Right.

22 MEMBER ROSEN: But now that you raise it,

23 I am concerned about other plants that may not have

24 done it that way and wondering what the justification

25 is at other places. It's just an aside thing.

1 MR. GALLETTI: Sure, sure. And I
2 understand, and we've asked those questions ourselves
3 when we've gone out. I mean, that's one of the
4 questions we asked, how did you perform this review,
5 and, quite frankly, we have not seen, in the cases
6 where they did not perform it under their Appendix B
7 program, any detriment in the process.
8 MEMBER LEITCH: Well, that may be so, but
9 I don't know. P.T., are you listening? I mean, for
10 plants that are conducting license renewal activities
11 not in accordance with their Appendix B commitments?
12 I don't think that's correct.
13 MR. GALLETTI: I don't know if I'd
14 characterize it that way. As much as the process that
15 they use and implemented, the procedures that they use
16 and implemented are not necessarily what they would
17 characterize as quality procedures in accordance with
18 their Appendix B requirements.
19 MEMBER ROSEN: That's what I'm having a
20 problem with.
21 MR. GALLETTI: Okay.
22 MEMBER ROSEN: We can talk about this
23 offline.
24 MR. KUO: Yes, we can talk about that
25 later on. I think that there is probably a

1 misunderstanding here that I want to clarify myself.

2 MR. GALLETTI: But again, for the sake of

3 the St. Lucie review, I think it's clear that their

4 entire process was done under their Appendix B

5 program, and we did find that acceptable.

6 As to the findings, the one major issue

7 that we did have regarded the 10 CFR 50.54 (a) (2)

8 issue, what we generically term the seismic II over I.

9 And initially, when the application had come in to us,

10 the licensee had performed an internal evaluation of

11 what they characterized as their A2 issues, the non-

12 safety effect and safety. However, just about at the

13 same time, the staff was crafting and implementing

14 their interim staff guidelines on this particular

15 issue. And as you recall, we issued, actually, two

16 staff guidelines, one related to the piping segments

17 and the fluid-filled piping systems, and the second

18 one related to those non-fluid-filled piping systems

19 or other types of SSC's that may come into

20 consideration.

21 As a result of the audit, we had lengthy

22 discussions on this issue, just articulated, again,

23 the staff's positions and tried to clarify for the

24 applicant exactly what we were expecting of them in

25 terms of a supplemental review. That is, what sort of

1 industry operating experience and site operating
2 experience did we want them to look at, and,
3 basically, the process or methodology that they would
4 use to explore any additional SSC's, which may have to
5 come into scope.
6 As a result of that effort, we did issue
7 an RAI, and the applicant came back with what I'll
8 characterize as an extremely detailed, lengthy
9 response to that request. And what the licensee
10 applicant did is they went through an areas-based
11 approach, identified the structures which housed both
12 the safety and non-safety, and then rather than just
13 summarily include everything within those structures,
14 they actually went beyond that to do a pretty detailed
15 review and analysis of the types of interactions that
16 could be expected in terms of leaking, pipe breaking,
17 physical impact, those sorts of things, as well as
18 look at the susceptible equipment. That equipment,
19 whether it was safety related, whether there were some
20 features in place to ensure that any potential hazard
21 would not affect it. Or if a potential hazard could
22 affect it, if it was in some way qualified to handle
23 those sorts of environmental concerns.
24 Again, we went through that evaluation.
25 We considered the way they implemented it and their

1 methodology for evaluating that to be very good. As
2 a result, they included some additional systems
3 interscope, and they expanded systems that were
4 already in scope for other regulatory reasons. I
5 think Noel will get into some of the specifics of what
6 specific components they may have included as a
7 result.
8 But overall, I guess our general
9 conclusion is that their methodology and
10 implementation of that methodology was very robust.
11 Their process was very well defined, and their
12 implementing guidance the engineer instructions. We
13 felt, as a result of many of their reviewers actually
14 having had experience at Turkey Point previously, they
15 were very well versed in the license renewal process,
16 understood the methodology to implement, and were able
17 to do so.
18 In addition, the licensee provided what I
19 considered rather decent training to their engineering
20 staff, and that encompassed about four different
21 training reviews: some initial on the license renewal
22 review process, formal training on the implementation
23 guidelines and some of the technical tools that they
24 to place to do that. They've got an online database
25 that they use specifically for some of this activity;

1 it took some time to train on that. And most
2 recently, they've been doing some training again with
3 their engineering staff to try to get a sense for the
4 administrative controls associated with commitments,
5 license renewal commitments.
6 So with that, we felt that there was
7 reasonable assurance that their methodology was
8 appropriate.
9 MR. DUDLEY: So I continue?
10 CHAIRMAN BONACA: Yes, please. You have
11 20 slides and one hour.
12 MR. DUDLEY: Okay. What I'm going to do
13 very quick is provide an overview of the scoping and
14 screening results and, secondly, the aging management
15 review process. The purpose of the staff's review of
16 the results of the applicant's scoping and screening
17 methodology is to verify that the applicant has
18 properly implemented its methodology. The staff
19 focuses its review on the methodology results. To
20 confirm that there is no omission of the plant-level
21 systems and structures within the scope of license
22 renewal and that there is no omission of mechanical
23 systems and components, structures, or electrical and
24 I&C components, they are subject to an aging
25 management review.

1 To conduct its review, the staff used
2 guidance from the license renewal standard review plan
3 and Interim Staff Guidance. The staff reviewed system
4 drawings indicating license renewal boundaries,
5 previous license renewal application reviews, and
6 information in the updated safety evaluation reports
7 to verify there were no omissions in the applicant's
8 results.
9 As part of this portion of the staff
10 review confirmed that the applicant's responses to
11 Interim Staff Guidance issues concerning station
12 blackout, the II over I issue, and ventilation fan
13 damper housings did not omit any structures or
14 components.
15 The conclusion required to be reached by
16 the staff is that there is reasonable assurance that
17 the applicant has appropriately identified components
18 subject to an AMR in accordance with the requirements
19 stated in 10 CFR 54.21 (a) (1). Any questions on the
20 scoping and screening results?
21 I'll go on to the aging management review
22 process. The purpose of the staff's review of the
23 applicant's aging management review results is to
24 verify the applicant has identified the appropriate
25 aging management program for the various combinations

1 of materials, environments, and aging effects
2 associated with the structures and components that are
3 within the scope of license renewal.
4 In this case, the staff used existing
5 regulatory requirements or guidance to reach a
6 conclusion on the appropriateness of the aging
7 management program identified by the applicant. This
8 slide contains a partial list of the documents used.
9 Since the applicant did not claim credit
10 for its aging management reviews being consistent with
11 the GALL report, the staff did not reference the GALL
12 reports in its evaluation of the aging management
13 review results. However, in some cases, the staff
14 used the technical information in the GALL report to
15 provide justification for the acceptability of the
16 applicant's results.
17 The staff reviewed the aging management
18 program results in Chapter Three, which are identified
19 in six separate system sections, as you see listed on
20 the slides. The conclusion required to be reached by
21 the staff is the applicant has demonstrated the aging
22 effects associated with different structures and
23 components will be adequately managed, so there is
24 reasonable assurance that the intended function will
25 be managed consistent with the current licensing basis

1 for the period of extended operations, as required by
2 10 CFR 54.21 (a) (3).
3 Next, I'd like to bring up Caudle Julian
4 from Region II, and he'll explain the inspection
5 process and summarize the inspection findings.
6 MEMBER FORD: Just while you're changing
7 your team here, when you say that review process, it
8 involves both sitting at a desk, as mentioned before,
9 and going over the program and discussing amongst
10 yourselves the technical details. When you go to the
11 plant, do you actually do a walk around the plant? Do
12 you stand by people as they're doing various tests,
13 etcetera?
14 MR. DUDLEY: I think Caudle will get into
15 that.
16 MEMBER FORD: Great. Fantastic.
17 MR. DUDLEY: And at this point, I'll ask
18 Mr. Julian, who is a team leader for the scoping and
19 screening inspections and the aging management review
20 inspections to bring its presentation to answer your
21 question.
22 MR. JULIAN: Thank you. In the first
23 slide, we give you an overview of our license renewal
24 inspection program. I think you've seen this material
25 before. We have a manual chapter 25.16, which is a

1 high-level document, and a license renewal inspection
2 procedure 71002, which gives us a description of the
3 work we're to do.
4 For each inspection, we put together a
5 site-specific inspection plan that's reviewed and
6 approved jointly by the region and by NRR. And our
7 schedule is always adjusted to meet the review
8 schedule that's proposed by NRR. We have a pretty
9 much standard template for running through these now,
10 and the regions do their inspections at the
11 appropriate time to support NRR's work.
12 The resources that we use are a consistent
13 team of the same five inspectors. I think that's good
14 to carry on from plant to plant, so we gain
15 experience. And, from time to time, we lose one, we
16 had one retirement last year, so we have a training
17 program for replacement team members.
18 MEMBER LEITCH: Do you take a focused look
19 at those same four or five systems that we referred to
20 earlier in the scoping and screening inspection?
21 MR. JULIAN: We look at nearly all the
22 systems during the scoping and screening, the things
23 that they brought into scope to verify that.
24 MEMBER LEITCH: Okay. What we were
25 hearing a few minutes ago about the scoping and

1 screening inspection, they focused on five particular
2 systems, I think I heard them say.
3 MR. JULIAN: We can take a much bigger
4 sample than that with five inspectors.
5 MEMBER LEITCH: Okay, thank you.
6 MR. JULIAN: Our inspections consist of,
7 as we slow on the next slide, the scoping and
8 screening inspection, aging management program
9 inspection, and we have the opportunity to do a third
10 optional inspection, and that decision is made by our
11 regional administrator, Louise Reyes.
12 MEMBER LEITCH: Has that decision been
13 made in the case of St. Lucie?
14 MR. JULIAN: Yes.
15 MEMBER LEITCH: And what was that
16 decision?
17 MR. JULIAN: We decided that we do not
18 need to do a third inspection for the St. Lucie plant.
19 They came out very clean and very few open items, if
20 any, in my first inspection.
21 Maybe I can answer your question about
22 scoping and screening. The scoping and screening
23 inspection, the objective is to confirm the output of
24 the process, to confirm the applicant included the
25 appropriate systems, structures, and components in the

1 scope of license renewal. It's one week in length,
2 and this one was done October 21 - 25, 2002 at St.
3 Lucie at the site. We have done them at corporate
4 office, where that's more appropriate where the work
5 is done there. But we were lucky that it's all done
6 at the St. Lucie site, which we think is much better.
7 CHAIRMAN BONACA: You do preparation right
8 before the meeting, so you know already where you want
9 to look probably.
10 MR. JULIAN: Yes, yes. The way we break
11 out the work on this is that we go through the list of
12 systems that the applicant puts in in Chapter Two,
13 and, in that table, which they all have, they'll
14 either say, "This system, we decided, is in scope,"
15 or, "Some of them, we decided, are not in scope." And
16 we make a selection of a large number of systems, not
17 all, but all major safety-related systems and systems
18 important to safety, and some that they said are not
19 in scope but we think might be candidates for that.
20 And I divvy this up amongst the inspectors, and
21 they're all assigned a workload of those for the
22 scoping and screening process.
23 So, here, we're focusing on the systems,
24 and they're to look at the boundary drawings, which
25 all the applicants provide, and any written

1 documentation, which all applicants have, which
2 supports why this system is in scope. In particular,
3 we're interested on the edges of a safety-related
4 system. On the boundary drawing, there may be things
5 where we'll discuss with the applicant why isn't this
6 particular piece in scope. And we also address, as I
7 mentioned, the notes to see if we agree with the
8 decisions that they made.
9 At St. Lucie, we thought that they did a
10 good job, and we concluded that the scoping and
11 screening process was successful in identifying those
12 system structures and components needing to be given
13 an aging management review. And their documentation
14 was a very good quality, we thought, with very few
15 minor exceptions that were --
16 MEMBER LEITCH: Did they use a process
17 that we heard about at Peach Bottom called
18 realignment? That is where certain non-safety systems
19 adjacent to safety systems were scoped with the safety
20 system. For example, where you had, say, an airline
21 penetrating containment, the compressed airline might
22 not necessarily be a safety system, but they included
23 that portion of the line to the outside valves, inside
24 and outside valves as part of the containment.
25 Another approach would be to take the compressed air

1 system and put it in scope and exclude all the other
2 stuff that wasn't part of the safety function.
3 MR. JULIAN: Happily, they did the latter.
4 MEMBER LEITCH: They did the latter?
5 Okay.
6 MR. JULIAN: Yes. I'm glad we didn't have
7 to contend with realignment at St. Lucie. If they had
8 an instance like that where a portion of the
9 instrument air system needed to be in scope, they
10 would select that portion of the instrument air system
11 out to a boundary valve that needs to be in scope, and
12 they would bring it in. So they would just bring in
13 the pieces of support systems that they needed.
14 Also, of course, you'd see, at containment
15 penetrations, there would be many, many systems that
16 are non-safety related that penetrate containment, and
17 only that portion between the boundary valves would be
18 in scope. Your answer directly is we didn't have to
19 deal with the concept of realignment.
20 MEMBER LEITCH: Okay.
21 MR. JULIAN: We think that's a good thing.
22 Realignment doesn't seem to lend itself well to using
23 the plant's existing, you know, documentation system,
24 and it seems like it would be very confusing.
25 MEMBER LEITCH: You wind up in the same

1 place, but it's just a matter of how you get there.

2 MR. JULIAN: The next inspection is the

3 aging management program inspection, and the objective

4 here is looking at the output to confirm that the

5 existing aging management programs are working well

6 and to examine the applicant's plans for establishing

7 new aging management programs and enhancing existing

8 aging management programs. That was two weeks in

9 length, and the dates were January 13 through 17 and

10 January 27 through 31.

11 And in this inspection, we were trying to

12 look for things that are existing aging management

13 programs. We want to know how well they've been

14 working, for example. So the boric acid corrosion

15 program that they've had for years will let me see the

16 results from the last two outages, one for each unit,

17 where you did walk down the boric acid problems and

18 let me see the records of what came out of that and

19 let me see your chemistry results for the cooling

20 system for the last two or three months.

21 MEMBER FORD: And then you go and look?

22 MR. JULIAN: That's right. We look, first

23 at the records, and if there are things that we can

24 do, can observe that are ongoing, we will do that.

25 Seldom, you happen to hit right at the right time, you

1 know, that you can actually see some of these things,
2 but there are some things that happened.
3 And for the inspectors, the systems that
4 they've been assigned during the scoping inspection,
5 I asked them a good opportunity that they have during
6 the first and second inspection to go out and about
7 with one of the system engineers and walk down that
8 system. And the feel there is we want to find out, to
9 the best of our observation, how the systems are being
10 maintained today to give us the confidence that the
11 utility will do good in the future. We know it's a
12 long ways off to the end of the 40-year period, but a
13 snapshot in time is better than none.
14 There were really no major, major problems
15 that came out of the aging management program
16 inspection. We ran across one where the electrical
17 cable manholes periodic inspection program needed
18 enhancements. I asked for the records that they did
19 on Unit 1 and Unit 2 looking at electrical manholes to
20 see if they are flooded. They do that about, I
21 believe it was every six months they were doing a
22 sample of them. And when we got to comparing it to
23 the drawings, it appears there was inconsistencies
24 between the two units down at the intake structure.
25 They were doing inspections on one unit but not on the

1 other. And, indeed, there were some safety-related
2 manholes that were not getting inspected at all.
3 The applicant agreed to that and has since
4 enhanced that program, and I've been told that that
5 has been fixed up now. The good news was that, for
6 the manholes they were inspecting, there were very few
7 instances where there was flooding over electrical
8 cables. There was one a year and a half ago that had
9 to be pumped out, but it was, luckily, a non-safety
10 related.
11 MEMBER ROSEN: Everybody has yards,
12 everybody has manholes in the yards, everybody has
13 manholes in the yards where rain occurs. It's not the
14 first time we've heard about this. Is there something
15 we need to do with the ISG here maybe? I don't know.
16 It just seems to me that that subject keeps coming up
17 in these reviews.
18 MR. JULIAN: Yes, it does. It's one of
19 our favorites for inspection during these aging
20 management programs.
21 MEMBER ROSEN: And it's a real problem.
22 I mean, sites need to make sure that those programs
23 are working and are corrective.
24 MR. JULIAN: And as we discussed before,
25 some people have very good programs, and some people

1 have very rudimentary ones. And I think that St.
2 Lucie, in my opinion, was somewhere in the middle.
3 They were doing this as a PM, a preventative
4 maintenance item, and I don't think it received the
5 proper management attention to make sure that they had
6 captured the correct sample to get it done rigorously,
7 and I'm told that they have rectified that now.
8 MS. FRANOVITCH: Caudle, this is Ronnie
9 Franovitch with the staff. In our GALL report, we do
10 have an A&P that addresses cables exposed to moisture
11 and significant moisture and how that's defined, and
12 it's really a 10-year test. We're in the process of
13 updating the GALL report to add programs that involve
14 things like inspection for moisture. I don't know
15 that we would need to write an ISG on that, but we may
16 be augmenting the GALL report to reflect what
17 applicants have done in addition to that 10-year test.
18 So I just wanted to mention that in passing.
19 MEMBER ROSEN: Yes, a 10-year test doesn't
20 really thrill me. I mean, it rains much more
21 frequently, if you're lucky, than that.
22 MS. FRANOVITCH: Yes. The staff
23 recognizes that 10 years is an awful long time, so
24 that's why we may be adding other programs that
25 involve inspection and reconsider the effectiveness of

1 the 10-year test.

2 MR. JULIAN: Well, the testing I think

3 that you're considering is actual cable testing --

4 MS. FRANOVITCH: That's correct.

5 MR. JULIAN: -- for continuity, and the

6 industry is still working with what kind of a test to

7 actually develop for safety-related electrical cables.

8 Typically, you see all the plants have some

9 rudimentary inspection of electrical manholes and a

10 frequency of six months, especially if you have a

11 rotation, and focus on the ones that are problems to

12 you again and again is the way to do this.

13 MR. HALE: I think it's important to note

14 that, at St. Lucie and at Turkey Point as well, if you

15 recall, for our median voltage cable, it's lead-

16 sheathed, which is designed for submergence. It was

17 an electrical standard that we put in place, even in

18 our T&D area. And the industry experience indicates

19 that the cable itself in low-voltage applications is

20 not impacted by moisture.

21 Our primary focus here was the supports

22 and the structural steel and everything else that's

23 associated with this electrical cable in terms of the

24 maintenance. It's still a good practice to maintain

25 these manholes, you know, in terms of reducing the

1 moisture. From an electrical standpoint, though, in
2 the way we performed our electrical aging management
3 review, from a median-voltage standpoint, moisture is
4 not an issue; and from a low-voltage standpoint, the
5 industry data would support that there's not an issue
6 with moisture for low-voltage cable.
7 MEMBER ROSEN: But I heard you say it's a
8 good practice to keep the manholes dry. I don't think
9 a good plant lets their manholes fill up with water
10 and stay that way for a long time. It should be
11 detected fairly quickly, the manhole is pumped out and
12 sealed.
13 MR. HALE: I couldn't agree with you more.
14 The case at St. Lucie, one of the issues we had is not
15 all of the manholes had sump pumps in them, so they
16 were inspecting the manholes with sump pumps, but they
17 weren't inspecting the holes that drain into that one
18 manhole that had the sump pump, and we needed to be
19 looking at those other manholes. So that's why we
20 went ahead and took fairly aggressive action to make
21 sure that we were looking at all manholes.
22 MR. JULIAN: And we agreed with that.
23 That's the reason we continued to pursue this as an
24 inspection item continually.
25 MEMBER LEITCH: Where there are new or

1 enhanced aging management programs, not just manholes,
2 is St. Lucie implementing those programs now, or are
3 we waiting for 40 years to --
4 MR. JULIAN: In the future. They have an
5 action item tracking system that they have
6 constructed, and they're going to begin work to revise
7 procedures and to construct these programs and put
8 them in place over time. I don't know exactly what
9 their schedule and goal is, but they did not say we're
10 not going to do anything until you're 39, as some
11 applicants have done.
12 MEMBER LEITCH: For example, on this
13 enhanced manhole inspection and pumping-out program,
14 there's no commitment to do anything with that until
15 you're 39 1/2 but maybe voluntarily --
16 MR. JULIAN: That's one that they
17 voluntarily did; that's done. That's been finished.
18 MR. HALE: And I'd like to point out that,
19 although our commitments communicate that we'll have
20 these done by the end of the current licensing period,
21 we took a pretty aggressive stance on implementation.
22 For example, at Turkey Point, we already implemented
23 70 to 80% of the commitments and integrated them into
24 plant procedures, so we've taken a tact that we will
25 implement everything we can reasonably get done, with

1 the exception of those where the inspection is going
2 to be performed sometime in the future. Although
3 that's not what's communicated in our formal
4 commitments, that's the tact we're taking internal.
5 MR. JULIAN: All right. We concluded,
6 overall, that the documentation for aging management
7 programs was of good quality. And with respect to
8 plant condition after our inspectors had gone all over
9 the place looking at plant systems, we were very
10 favorably impressed. One of my inspectors was a
11 former resident inspector at St. Lucie and stayed
12 there for a number of years, and I've been there for
13 a number of years, and our overall conclusion at St.
14 Lucie is that the plant condition continues to improve
15 from what it used to be in past years.
16 MEMBER ROSEN: Haven't got rid of the
17 noseeums, though. Still out there? Those are real
18 fleas.
19 MR. JULIAN: Okay. One more thing is that
20 a question was asked earlier. The region
21 administrators decided that we don't need a third
22 optional inspection because the applicant has already
23 established a tracking system for future actions, and
24 we see that they're very responsive in their efforts.
25 That's all I have. Any questions? Thank you.

1 MR. DUDLEY: Earlier today, the applicant
2 presented its aging management program for the aging
3 effects of phosphate on concrete structures. Dr.
4 David Jeng will present the staff's assessment of the
5 applicant's management of the aging effects of
6 phosphate on concrete and embedded rebar, and I will
7 turn the meeting over to him.
8 MR. JENG: Good afternoon. My name is
9 David Jeng, and I'm a member of the Mechanical Branch.
10 I am one of the reviewers who reviewed the Section 3.5
11 containments structures and component supports.
12 Today, I would like to briefly report to
13 you about the staff's review of below-grade concrete
14 aging management. The staff has a position for the
15 concrete which are below grade that is inaccessible.
16 If they do not expose to the environments, then there
17 will be no need for inspection of those concrete
18 elements. However, if the environment is established
19 to be an aggressive one, then the staff requires an
20 applicant to propose an appropriate aging management
21 program.
22 The criteria we're judging on whether it's
23 an aggressive environment or not is quite
24 quantitative, and the criteria is shown in the GALL
25 report, which mainly consists of three points. The

first one is the pH of the environment should not be less than 5.5, and the second item is the chloride contents of the ground water in the soil environment should not be larger than 500 PPM. And the third item is solvent content requirements, which the staff maintains they should not exceed 1500 PPM.

In the case of the St. Lucie site, as it was noted by the earlier presentation, the site is quite unique in having an aggressive environment. Specifically, the content of the chloride in the St. Lucie site ground water is in the order of 10,000 to 25,000 PPM compared to 500.

MEMBER ROSEN: 10,000 to what?

MR. JENG: 25,000.

MEMBER ROSEN: 35,000 is pure sea water, isn't it?

MR. JENG: This is chloride.

MEMBER ROSEN: Chloride environment in pure sea water is what? What is the chloride content of pure sea water?

MR. JENG: I'm not an expert on that one.

MR. HALE: I think it's around 22,000 PPM.

MEMBER ROSEN: 23,000. So this is actually, it's higher underneath the St. Lucie, it can be higher on the St. Lucie than in the open sea.

1 MR. HALE: I don't know. I'm just quoting
2 sea water.
3 MEMBER ROSEN: It sounds like sea water to
4 me when you're talking 35,000.
5 MR. HALE: Yes, our ground water is sea.
6 We're right on the ocean.
7 MEMBER ROSEN: Exactly.
8 MR. JENG: Now, in terms of sulfate of the
9 St. Lucie ground water, it's in the order of 1,000 to
10 4,000 PPM, which, I think, is exceeding the staff's
11 1500 PPM. So for this reason, the applicant took the
12 initiative in the environment is a very aggressive
13 one, and they are calling the proposed aging
14 management program to manage the aging.
15 The aging management program we are
16 proposing is for systems and structures. And the
17 program mainly contains two sub-items. The first one
18 the applicant is appointed to perform inspections of
19 their assessable below-grade interior concrete
20 elements in services. And the second item is they are
21 going to perform an inspection whenever and wherever
22 excavated structures which are exposed to the ground
23 water.
24 These two positions consistent with the
25 positions the staff has stated in the GALL report and

1 has been consistent with some other earlier review
2 actions. Therefore, the staff finds the proposed
3 approach is reasonable and adequate, and therefore, is
4 acceptable.
5 I would like to make a note that, this
6 morning, the applicant made a quite in-depth and
7 systematic presentation of how they are managing the
8 rebar concrete corrosion and how they assist the
9 phosphate, which may affect the aging of concrete.
10 The staff finds their presentation close on the
11 contents, and the conclusion drawn it's very
12 reasonable and adequate, and we express our
13 concurrence to their presentation information and
14 results.
15 This concludes my presentation.
16 MEMBER FORD: Could I just make a comment
17 on your last bullet, inspections conducted and
18 structures are excavated? In other words, you're
19 saying that they must inspect because they are over
20 the spec limit for chloride content, but the
21 inspections are going to be completely random in terms
22 of place and time; is that right?
23 MR. JENG: It's whenever they have the
24 occasion they have to do some excavation. It's not
25 required to go perform specific excavation. It's

1 when, for other reasons, in other reasons, they need -
2 -
3 MEMBER FORD: So in other words, it's
4 random?
5 MR. JENG: Sort of, yes. But you noted
6 that they presented this morning, there are four
7 cases, reasons they inspect it because of other
8 requirements.
9 MEMBER FORD: I recognize that. But if
10 you were an informed member of the public, and they
11 did find some concrete degradation in some future
12 date, how do you answer the concerned public because
13 you just didn't happen to inspect that region some
14 time? You would be in a terrible mess, wouldn't you?
15 MR. JENG: Very good, thorough thinking
16 about how we come up with this position. The basis,
17 based on very thorough research of research results is
18 presented in the ACI reports this morning and, also,
19 some 150 years of experience.
20 MR. DUDLEY: I think the answer to the
21 question is the applicant would have to treat it as
22 any inspection finding where aging degradation is
23 identified and put it into the corrective action
24 program to see if additional inspection should be done
25 to the structures.

1 MEMBER FORD: Well, are the parts in the
2 structure where, if it did occur, I mean, I agree with
3 you it's unlikely, but if it did occur, it would be a
4 huge impact. Are there places where it would be a
5 huge impact?
6 MR. JENG: If it did occur, it is the
7 staff's position to treat this item as a degradation
8 item, and they would take appropriate actions to
9 remedy the situation.
10 MEMBER FORD: Maybe I'm not being very
11 clear. You've made the case that these items in
12 accessible areas or below-grade areas should be
13 inspected, and you're saying that, okay, it doesn't
14 really matter; we'll just do it randomly at time and
15 place as chance would dictate.
16 MR. JENG: We inspect it first opportunity
17 comes along.
18 MEMBER FORD: Yes, but that's random in
19 terms of time. Oh, at the first opportunity?
20 MR. JENG: Yes. When occasion somebody
21 have to excavate some part of the structures because
22 of other operational requirements or whatever the
23 reason.
24 MEMBER FORD: But that's random.
25 MR. JENG: That may happen next year, or

1 it may happen next three years.

2 MR. DUDLEY: Yes, there's a concern about

3 requiring applicants to go out and dig up around

4 foundations since there is a rubber barrier or a

5 membrane around the structure. So there's a trade-off

6 between going --

7 MEMBER FORD: Hold on, Noel. The rubber

8 membrane is not stopping the sea water getting to the

9 concrete.

10 MR. JENG: It will stop the sea water, but

11 only when it's damaged or degraded, then some sea

12 water may --

13 MEMBER FORD: Well, let me ask a physical

14 question. Are there situations where you could get

15 sea water in contact with the concrete?

16 MR. JENG: I would say yes.

17 MEMBER FORD: Okay. So the rubber doesn't

18 matter.

19 MR. HALE: If I could, Dr. Ford, there's

20 a couple of other things beside just the excavation

21 part of it. One, we do inspect, for example, the heat

22 sink dam regularly. This is a structure that is under

23 water constantly. The other aspect is that we've also

24 included internal inspections of the surfaces of that

25 concrete that's actually below grade. For example, in

1 the auxiliary building, there are concrete, you can
2 actually go the flow, the flow is actually below the
3 level of ground water, and actually look at bleed
4 through and other indications that would tell you that
5 you do have, you know, some effect from the salt water
6 on the concrete. So it's not just the excavation.
7 The excavation is in addition to things that we do
8 regularly.
9 MEMBER ROSEN: Are there any techniques
10 for assessing the integrity of the bond between the
11 rebar and the concrete, from external to the concrete,
12 some sort of a radar technique or anything that could
13 be applied from inside, obviously? I mean, some kind
14 of device you could take down to the lowest levels of
15 the plant and put up against the wall that you know is
16 external and see what the interior reads out, see
17 whether there's any integrity?
18 MR. JENG: Talking about the bond between
19 the steel valves in the surrounding concrete?
20 MEMBER ROSEN: Yes, the bond, and you can
21 maybe assess the continuity or the integrity of the
22 rebar. I'm just asking a question about whether any
23 such device is available.
24 MR. JENG: As a concrete structure
25 engineer, I know, yes, testing the strength of the

1 concrete, and I don't know of any established
2 procedure to determine the bond between the rebars and
3 the surrounding concrete.
4 MEMBER FORD: So you could go down there
5 and determine the strength of the concrete.
6 MR. JENG: Yes.
7 MEMBER FORD: Which would be an indirect
8 measure of whether or not you've had leakage, external
9 sea water leakage into the concrete, which has damaged
10 the concrete, presumably damaged the bond between the
11 rebar and the concrete, and then damaged the rebar,
12 which is carbon steel. Is there any way other than
13 waiting for it to leak, which is what this period
14 inspections of structural interiors is, or waiting
15 until you happen to excavate it? Is there anything
16 better than that?
17 MR. JENG: The reason we are assuming this
18 position is based on so-called benefit and cost
19 evaluation. I just stress that, over the 150 years of
20 the civil engineering practices and experiences, we
21 haven't experienced any major concern of the sea water
22 being put against the concrete wall would certainly
23 cause some appreciable or a big concern about the
24 safety or the loss of strength.
25 Occasionally, it may have happened, but

1 those are infrequent. And whenever they occur, there
2 are processes in place to handle this.
3 MEMBER FORD: I think you have to qualify
4 your statement. When you saying 150 years, you are
5 not including, you're not confining yourself just to
6 nuclear structures. You're talking about 150 years,
7 and I don't see how you can say that concrete does not
8 degrade in sea water. I don't follow your factual
9 statement.
10 MR. JENG: Maybe we should define what do
11 you mean by concrete degrade? What do you consider to
12 be a degrade? Engineering, it's our own view why it's
13 okay. When you degrade concrete to the extent it
14 crumbles down and loses the strength and loses
15 function, that's based on the reasons this morning:
16 high-strength concrete, low cement/water ratio,
17 adequate cover, and good aggregate, good cementing,
18 and good construction placement with design. All this
19 stuff is basis for past experience which would almost
20 assure -
21 MEMBER FORD: But you've got 150 years of
22 experience with those specifications for concrete?
23 MR. JENG: No. Experience of concrete
24 construction in embedded sea water situation for 150
25 years. This is off my head, but I think it's a

1 reasonable number. Thank you very much.

2 MR. DUDLEY: Next, I want to go through

3 the staff's review of aging management programs. The

4 purpose of the staff's review of aging management

5 programs is to determine whether the programs will

6 adequately manage the associated aging effects. For

7 the aging management programs that the applicant

8 claimed were consistent with GALL report, the staff

9 verified consistency with GALL and the appropriate

10 further evaluations were completed and evaluated

11 associated operating experience.

12 For the aging management programs that are

13 not consistent with the GALL report, the staff

14 reviewed the 10 attributes of each program, similar to

15 what you have seen in previous applications. In

16 addition, the staff determined that the final safety

17 evaluation report supplements contained an adequate

18 summary description of the programs and activities for

19 managing the associated aging effects.

20 This next table is taking information from

21 Section 3.0 of the SER, and it summarizes the

22 information concerning the 24 aging management

23 programs in those tables. There were six new

24 programs, and there was also one new program added as

25 a result of a request for additional information, and

1 there are 17 existing programs. There are 10 common
2 programs, and then 14 system specific programs. And
3 there were 10 GALL programs and 14 non-GALL programs.
4 The conclusion required to be reached by
5 the staff is that the applicant demonstrated that the
6 aging effects associated with the structures and
7 components will be adequately managed so that the
8 structures and components will perform their intended
9 functions. The staff also had to reach the conclusion
10 that the FSAR supplements contained an appropriate
11 summary description of the programs and activities for
12 managing the effects of aging as required by 10 CFR
13 54.21 (d).
14 Next, we can get into the --
15 CHAIRMAN BONACA: I have a question. Some
16 of these programs, for example the galvanic corrosion,
17 if I remember, susceptibility program contained
18 commitments to either visual or volumetric inspections
19 to be performed. When will these decisions be made?
20 I mean, the programs are vague still about which ones
21 are going to be selected.
22 MR. DUDLEY: The programs will need to be
23 submitted and approved prior to the period of extended
24 operation.
25 CHAIRMAN BONACA: Okay. So by that time,

1 you'll have an iteration because you made us agree,
2 for example, with a proposed approach.
3 MR. DUDLEY: That's correct.
4 CHAIRMAN BONACA: So that's part of the
5 implementation phase.
6 MR. DUDLEY: Yes, and the list of
7 commitments made that are at the end of the SER can be
8 used by inspection teams a few years prior to the end
9 of the present operating period to verify that all the
10 commitments have been met and the programs have been
11 submitted and reviewed and accepted before they enter
12 the period of extended operation.
13 CHAIRMAN BONACA: But there will be, also,
14 a license renewal specific inspection, right?
15 MR. DUDLEY: That's correct. We are
16 working and developing an inspection program
17 specifically for license renewal.
18 CHAIRMAN BONACA: All right.
19 MR. DUDLEY: I'm not sure if and when you
20 want to take a break, Tim, but why don't we continue
21 on with the TLAA's and see how far we get and how
22 quickly.
23 MR. HALE: If I could, on the aluminum
24 bronze, we have confirmed that our configuration is
25 consistent with what's in the application in that our

1 aluminum bronze components are valves, pipings, and
2 fittings associated with vent strains and
3 instrumentation.
4 MEMBER ROSEN: Which means less than --
5 MR. HALE: Two and a half-inch and
6 smaller.
7 MEMBER ROSEN: Okay. So, presumably, you
8 wouldn't have any cast flanges in two and a half-inch
9 and smaller.
10 MR. HALE: Presumably. Also, we have
11 aluminum bronze pump cases, but we actually --
12 MR. MENOCAL: In addition, the intake
13 cooling water pump casing, we have sections that are
14 aluminum bronze. But, from what I recall, those
15 casings have a coating on the inside, I guess like a
16 core glass coating; it's an epoxy coating to keep down
17 the potential for erosion of the pump.
18 MR. HALE: Well, you might mention that
19 they're also removed under the PM program and replaced
20 as required.
21 MR. MENOCAL: Oh, yes. Those are, and
22 that coating is maintained, periodically disassembled,
23 and refurbished. We have a spare pump that we use to
24 slop out. I don't know the frequency off the top of
25 my head. I think that was a question we had under one

1 of the RAI's from the staff.

2 MR. BAILEY: This is Stuart Bailey. Just

3 for clarification, also, for those pump casings,

4 applicant is not relying on leakage detection for

5 those. Applicant uses their periodic surveillance and

6 preventative maintenance program for those.

7 MEMBER ROSEN: So they're covered by a PM

8 program?

9 MR. MENOCAL: That's correct.

10 MR. HALE: And it's on a set timeframe

11 based on operating experience.

12 MR. MENOCAL: Right.

13 MEMBER ROSEN: Okay. I'm checking that

14 one off. Thank you. Maybe this is a time, while

15 we're paused here and before we go too far away from

16 what we just got done talking about, Peter, for me to

17 comment about my feelings about what we've heard about

18 below-grade concrete in aggressive ground water

19 environments.

20 It seems to me that we're undershooting

21 that target dramatically. Periodically, looking for

22 interior leakage is a good thing, but it's after the

23 fact. And being opportunistic, looking at exterior

24 structures whenever they're excavated is a good thing

25 but, as you suggested, it's random. It seems to me

1 that, given the importance of the integrity of
2 structures exposed to aggressive ground water
3 environments, there ought to be something more done.
4 I would hesitate, sitting here, to say
5 why, but it should be something that, at least in a
6 sampling way over time, verifies the integrity of the
7 concrete that's exposed to these environments. You
8 could think of something like maybe a coring
9 occasionally at some place, say, yes, take the core
10 out, from the inside obviously, you don't have to
11 excavate, you just go in and drill a core out, say,
12 "Oh, that looks beautiful, just like the day it went
13 in," or, "My gosh, it's all crumbly," and that would
14 be important information. And it seems to me, while
15 I recognize that staff doesn't require it, I'm sitting
16 here thinking what I would do if I had such a plan.
17 I'd certainly want, occasionally, to have more than
18 just, "Well, it isn't leaking, and I haven't found any
19 leakage." It could be happening, and, if it were,
20 that would be extraordinarily important.
21 MEMBER FORD: I sympathize with the
22 technical difficulty of doing this, and I tend to
23 agree with the presenters on both sides that you asked
24 what do I think, and, yes, I think the likelihood of
25 damage is very high. But if it did occur, then the

consequence could be very great. Therefore, it would be wise to issue a suggestion.

MEMBER ROSEN: Obviously, we're not talking about a widespread sampling program, so you could miss it. You could take the core, and it could look very good in one place, and, 10 feet away, it could be aggressively be --

MEMBER FORD: I'm sympathetic with the idea of looking at the --

MEMBER ROSEN: Oh, I don't want them going in and penetrating the outside barrier.

MEMBER FORD: I'm assuming it was another destructive examination. I'm sympathetic to using that as a kind of Trojan horse, if you'd like. If it's corroding on the sea wall, then I better start to look at my containment.

MR. HALE: I think it's important to point out we do have surfaces that are exposed to sea water constantly that we do look at, and we have not seen degradation there. Where we have seen degradation in concrete have been on areas that are not exposed to salt water all the time, where there's splash or there's collection. For example, horizontal structures where you might get some water seepage that gets into the contract. We've seen that both at

1 Turkey Point and St. Lucie. But what I think the
2 information that we're presenting here is that, one,
3 by design, you build your concrete such that you would
4 not anticipate to see the kind of corrosion issues
5 we're talking about due to the pressure design, the
6 coverage, and that sort of thing. But in addition to
7 that, we've got surfaces of concrete that are exposed
8 to salt water continually that are visibly inspected,
9 and we have not seen degradation there.
10 So I think, on those cases where we have
11 excavated at St. Lucie, we haven't seen any. I think
12 that it builds a story that it appears that the design
13 standards that we've developed are performing as we
14 expected them to.
15 MEMBER ROSEN: And all we need is some
16 verification of that. In my opinion, all we need is
17 some verification of that, and maybe it's as simple as
18 a radar test, you know, looking for rebar integrity.
19 I don't know. Maybe it's some kind of non-invasive
20 test, perhaps, is all you need. Ultimately, you could
21 always do what I suggested first, which was coring
22 from the inside. I really don't want to do that, but
23 I really think that's not good enough. My judgment is
24 it isn't good enough to say we think it's okay because
25 of all the things we've done and the example we have

1 of the other varied concrete that's okay. It's an
2 issue of importance that should, to me, take some sort
3 of verification. That's just one person's feeling.
4 CHAIRMAN BONACA: This seems to me a lot
5 of information regarding experience with concrete
6 structures close to sea water before power plants. I
7 mean, bridges, spears --
8 MEMBER FORD: They would be uniformly bad
9 until you had these -- bridge structures, for
10 instance, are not --
11 MR. HALE: Falling apart.
12 MEMBER FORD: They are falling apart, a
13 lot of them. I grant you that they probably will not.
14 That's why I'm saying I don't think it's a huge
15 likelihood that --
16 MEMBER ROSEN: So you're saying experience
17 has not been good.
18 MEMBER FORD: But if it did occur because
19 you were not controlling the coring process or
20 something in that building process was not well
21 controlled and you'd have a weak point, then what
22 would the impact be? This goes beyond St. Lucie; I
23 mean this is our generic.
24 MR. KUO: If I may make a comment. Yes,
25 I agree with you. This is a generic, this is not St.

1 Lucie specific. That's the first thing. And I do
2 understand that you're concerned about the need for
3 maybe we say it's a better inspection. However, to my
4 knowledge, there have been some non-destructive
5 examination technique applied to concrete. The
6 experience that I knew of, okay, was not very good,
7 okay, because the aggregate of the concrete, okay. So
8 applying those to non-destructive techniques really
9 wasn't successful, as far as I know. It really
10 presents a very difficult task there.
11 Dr. Rosen talk about taking course. Good
12 idea. However, as you said before, how many course do
13 we have to take? Okay. So if we take the course
14 randomly, again, I'll be facing the same comments Dr.
15 Ford is talking about. How do you know it covered
16 everything? It is a difficult thing to do, and, also,
17 it's quite costly; let's face it, okay.
18 MEMBER ROSEN: Oh, I'm not thinking about
19 cost right now, frankly. I'm thinking about
20 feasibility and the need.
21 MR. KUO: Right. The feasibility is
22 there. We could, we could definitely. And then the
23 next question is whether do we have a need there?
24 Based on what the data, the experience that we have
25 collected, just like Mr. Jeng mentioned before, and

1 look at all the publications out from ATI, really,
2 what it tells us is if you construct the concrete,
3 design the concrete mix, then the potential for the
4 water getting into the rebar is not that great.
5 MEMBER FORD: If it is built according to
6 specifications, and I don't doubt the likelihood of
7 corrosion occurring or degradation occurring will be
8 small. But was it built according to specifications?
9 MR. KUO: That, I will have to refer to
10 Mr. Hale. However, I think, as a common practice
11 during construction, for each batch of concrete, we
12 will take a syringical test, and the concrete strength
13 depending on that. So when he said there's 5,000 PSI
14 concrete, that is based on all the syringical tests.
15 And when they construct this concrete structure there,
16 they have to take a test every so often. It cannot
17 exceed two inches or two and a half inches, so that
18 kind of quality control is there. If they follow the
19 quality control, I'm sure this concrete is built
20 according to the code. So that's the assurance, the
21 kind of assurance we have for this type of concrete,
22 especially nuclear plant structures. That's a little
23 bit my --
24 CHAIRMAN BONACA: We could raise the
25 question regarding any activities in construction. I

1 mean, you know, is it constructed the way it's
2 supposed to? I mean, hopefully, there was sufficient
3 inspection and testing during to assure that. Now,
4 still, there are questions, you know, but that
5 specific issue, was it built as it should have,
6 hopefully, was answered when it was constructed.
7 MEMBER FORD: Having been brought up in
8 the world of cracking, I am very sensitive to anybody
9 saying that, you know, it will never happen.
10 MR. KUO: My previous life was building
11 structures.
12 MR. DUDLEY: Okay. Next, we'll go through
13 four different TLAA's, and TLAA's are certain plant-
14 specific analyses that are based on explicitly assumed
15 40-year life, such as aspects of the reactor vessel
16 design. TLAA's also may have evolved since issuance
17 of the plant operating license. For example, analyses
18 supporting core barrel repair or the reactor coolant
19 system half-nozzle repairs.
20 The staff's review of TLA's confirm that
21 the applicant has evaluated the TLA's by verifying
22 either the analysis is valid for a period of extended
23 operation, or the analysis is projected to the end of
24 the period of extended operations and the results
25 continue to meet the design requirements, or there's

1 a program to manage the aging effects.

2 The first TLA I'll discuss is the reactor

3 neutron embrittlement, and that consists of three

4 separate analyses: calculation of the end of life

5 Upper Shelf Energy, the pressurized thermal shock

6 reference temperature, and included the pressure and

7 temperature limits as a discussion item since it's not

8 truly a TLAA.

9 The analysis of the upper shelf energies

10 for the different reactor vessel belt line materials

11 was projected to the end of a period of extended

12 operations. The results of the applicant's calculated

13 upper shelf energies for Unit 1 reactor vessel ranged

14 from 56 to 73 foot pounds, which are above the

15 acceptance criterion of 50-foot pounds. And the

16 results for Unit 2 range from 70 to 130-foot pounds,

17 which is, again, above the criterion. The staff

18 performed independent calculations to confirm these

19 results.

20 MEMBER WALLIS: How do they determine

21 these values?

22 MR. DUDLEY: It's a calculation done in

23 accordance with Reg Guide 1.99, and it's a

24 prescriptive process.

25 MEMBER WALLIS: Fluents? Is that an

1 equation for fluents?

2 MR. DUDLEY: I'll need some help from the

3 technical staff on this. Jim, can you help me out?

4 MR. MEDOFF: This is Jim Medoff with the

5 Materials and Chemical Engineering Branch. To do our

6 independent calculations, we have a reactor vessel

7 integrity database that includes all the belt line

8 materials for all the U.S. plants, including St. Lucie

9 1 and 2. For the neutron embrittlement assessments

10 for pressurized thermal shock and Upper Shelf, we did

11 independent calculations of all the materials, and the

12 methods in the database follow the guidelines of

13 regulatory guide 1.99, Revision II, which we've been

14 using for a long time.

15 MEMBER WALLIS: I thought that was all

16 about RTNDT and that sort of thing.

17 MR. MEDOFF: Well, RTNDT has to do with

18 pressurized thermal shock. The Upper Shelf Energy is

19 based on charpy impact data, and it's a different

20 criterion. It deals with ductal failures rather than

21 brittle failures --

22 MEMBER WALLIS: -- letting it from the

23 fluents, are you?

24 MR. MEDOFF: Yes, the calculations take

25 into account --